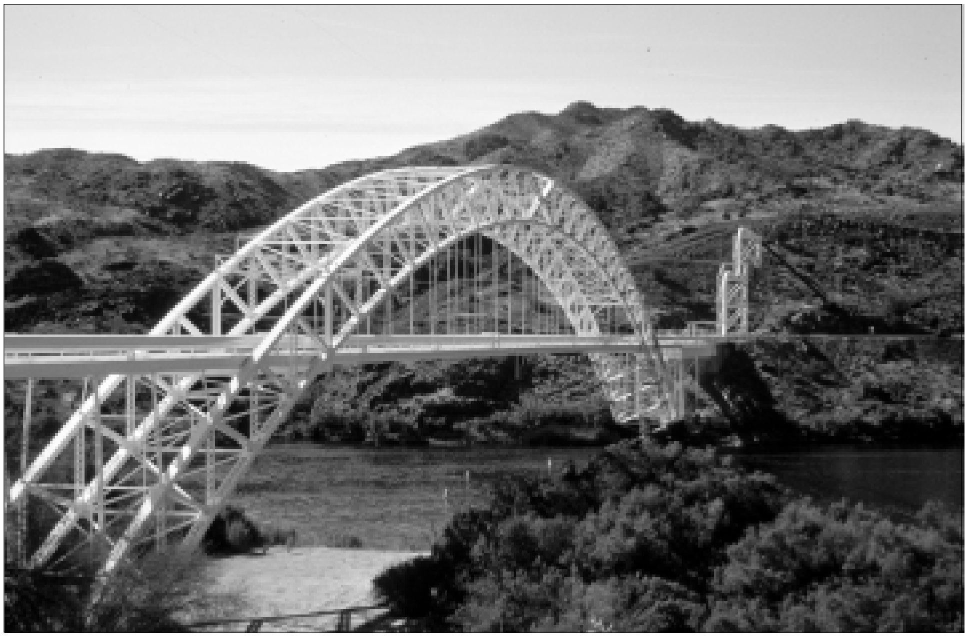
STAFF REPORT



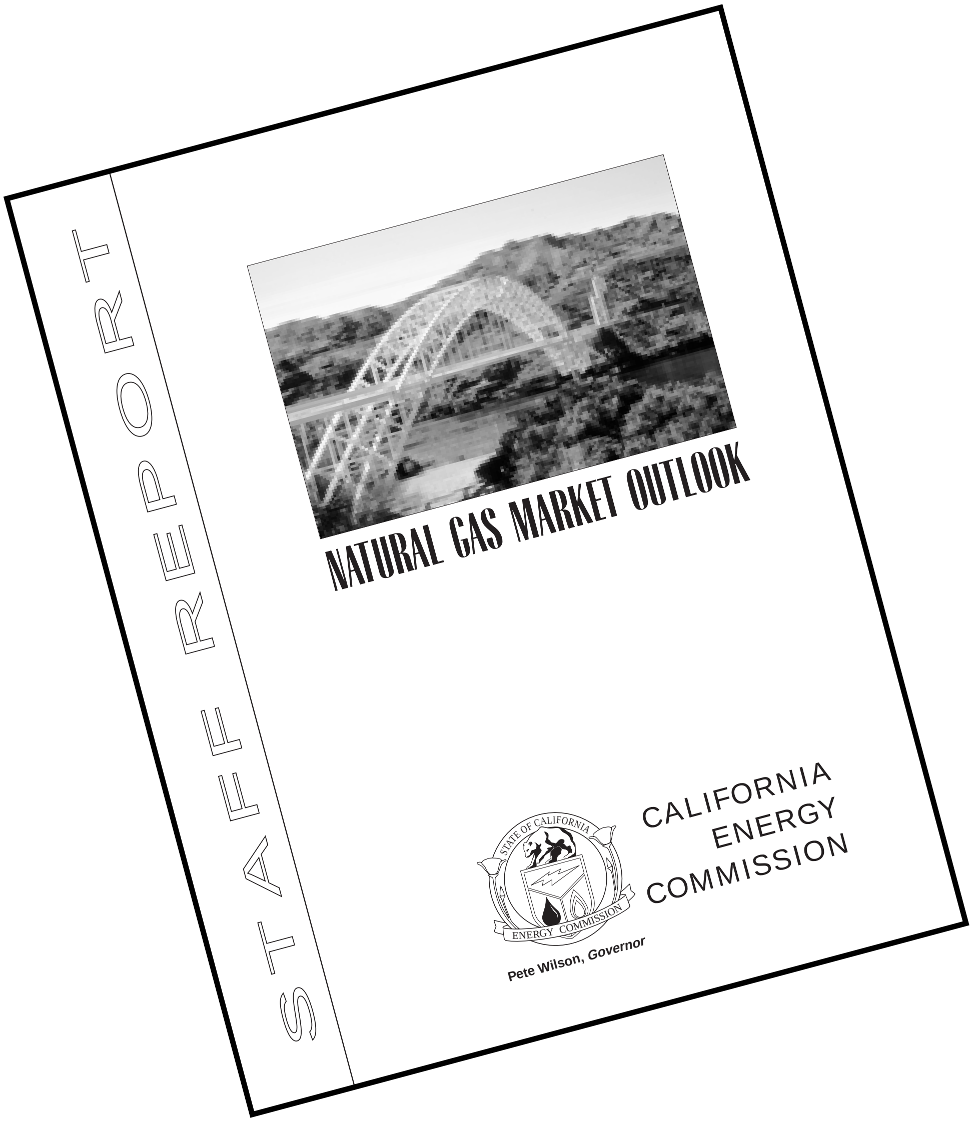
NATURAL GAS MARKET OUTLOOK

JUNE 1998

CALIFORNIA
ENERGY
COMMISSION

Pete Wilson, ***Governor***

P300-98-006



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Front Cover Photo

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The Topock Bridge is an essential part of the El Paso Natural Gas pipeline system, the largest system directly linking California with the San Juan, Permian, and Anadarko Basins. At the Arizona/California border, El Paso can transport nearly 1.7 trillion cubic feet per day of gas to two utility pipeline systems and an affiliated interstate pipeline company inside the state.

We wish to express our gratitude to those that played an active role helping staff develop the input assumptions underlying this price forecast. Specific acknowledgment is offered to Emil Attanasi of the U.S. Geological Survey, whose willingness to provide resource data from the USGS 1995 National Assessment has greatly enhanced the credibility of our resource assumptions. We are, as always, indebted to the members of the North American Regional Gas (NARG) Model Users Group for sharing views on updating the structure of the NARG model and specific views on the marketplace and those parties that commented on staff's proposed and revised forecasts.

Disclaimer: *The views and conclusions in this document are those of the staff of the Energy Information and Analysis Division and should not be interpreted as necessarily representing the policies of either the California Energy Commission or the state of California.*

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EXECUTIVE SUMMARY

The California Energy Commission is required under Section 25310(a) of the California Public Resources Code to prepare a biennial forecast of natural gas prices, supplies, and demand for California over a 20-year period. The forecast is developed in support of the ***Fuels Report***, a comprehensive report to be submitted to the Governor and Legislature describing emerging trends and long-range forecasts for fuels consumed in the state. The ***Natural Gas Market Outlook*** documents the Commission's forecast of natural gas prices and supplies for each end-use market sector in the state, adopted on March 18, 1998.

The methodology used to generate the end-use forecasts consists of two steps. The first step entails analyzing the continental market based on resource availability, natural gas transportation capacities and costs, and expected demand for natural gas in regional market sectors. The North American Regional Gas (NARG) model is the principal tool used by the Commission to assess natural gas market fundamentals and generate the California border price forecast. Basic inputs to the NARG model include estimates of resource availability, production costs, pipeline capacity and transportation costs, regional demand projections, and other parameters defining the market fundamentals. Different from previous forecasts, the model applies a methodology to account for reserve appreciation over time. The second step focuses on determining the end-use prices for each market sector in the state. The costs to distribute and deliver natural gas for each customer class is determined. These costs and the California border prices resulting from the first step are then combined to generate the end-use prices for each market sector in each natural gas service region within the state.

Continental Supply and Price Outlook

Natural gas supplies will remain plentiful for the next several decades. The total resource base (gas recoverable with today's technology) for the Lower 48 states is estimated to be about 975 trillion cubic feet (TCF), enough to satisfy current production levels for more than 50 years. Production from Lower 48 states is expected to increase from 17.1 TCF in the 1994 base year to 25.9 TCF in 2019. Gulf Coast and Rocky Mountain supply regions account for most of the increase during the next two decades. Alberta continues to provide the bulk of Canadian production. Canadian exports are projected to rise to 3.9 TCF in 2014 and remain at that level thereafter.

The average wellhead price in the Lower 48 states is expected to increase from $1.55 per thousand cubic feet (MCF) in 1999 to $2.05 per MCF in 2019 (in constant 1995 dollars), representing an annual average increase of 1.4 percent. In Canada, the average price is projected to increase 2 percent per year from $1.10 per MCF in 1999 to $1.65 per MCF by the year 2019. The expected growth rates in wellhead prices are considerably lower than previous Commission estimates, which have consistently been in the range of 3-4 percent. A major factor contributing to this lower growth rate is the incorporation of a reserve appreciation function in the NARG model. Details of the impacts of reserve appreciation are described in this Outlook.

Natural Gas Supplies and Prices at the California Border

Four producing regions supply California with natural gas. Three of them (the Southwest U.S., the Rocky Mountains, and Canada) provide approximately 85 percent of all gas used in the state. The remainder is produced inside California. Total supplies are expected to increase from 5.9 billion cubic feet (BCF) per day in the 1994 base year to 7.8 BCF per day by 2019. No significant changes are anticipated in the market shares of supplies from these four supply regions over the forecast horizon. Southwest supplies will continue to dominate, holding approximately half of the California market. Canadian producers will supply another quarter of the market, with the remainder split between Rocky Mountain and California suppliers.

The average California border price is expected to increase by 1.9 percent per year from $1.68 per MCF in 1999 to $2.46 per MCF in the year 2019.

California End-Use Natural Gas Price Forecast

End-use prices by customer sector and utility are shown in Table A for selected years of the forecast. The analysis indicates that natural gas prices to generate electricity in the Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (SoCalGas) service areas will be very competitive. Also, due to additional costs to transport natural gas through the SoCalGas service area, San Diego Gas and Electric Company (SDG&E) natural gas price for electric generation is about 30 cents higher than that in the SoCalGas service area. This trend will continue as long as the current pricing structure is maintained. The impending merger of SoCalGas and SDG&E and the unbundling of gas utility services could change this situation.

Need for Additional Interstate Pipeline Capacity to California

Despite the fact that excess interstate pipeline capacity now exists, additional pipeline capacity will be needed at the California border during the next two decades. Staff estimates a need for additional delivery capacity from the Rocky Mountains in 2004 and from Canada in 2009. Additional delivery capacity at Wheeler Ridge will be needed by 2009 to accommodate additional flows from these regions. Expansion of the pipelines moving San Juan Basin gas to California will be needed by 2004, while take-away capacity will be needed on the SoCalGas system at Topock (at the California border) by 2009.

TABLE A
CALIFORNIA BASECASE END-USE PRICE FORECAST BY SECTOR AND UTILITY
1995 DOLLARS PER MCF

Utility and Year	Core			Noncore					System Total
	Resid	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	
PG&E									
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1997	7.13	7.12	4.69	3.45	2.80	2.58	2.66	2.66	4.27
2000	6.09	6.08	3.42	3.01	2.05	1.98	1.99	1.99	3.36
2005	5.67	5.67	3.44	3.10	2.21	2.17	2.16	2.16	3.31
2010	5.59	5.59	3.49	3.21	2.37	2.34	2.31	2.31	3.33
2017	5.57	5.58	3.63	3.46	2.68	2.64	2.62	2.62	3.52
SoCalGas									
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1997	6.93	5.19	4.26	3.07	3.06	2.85	2.87	2.87	4.42
2000	5.91	4.20	3.28	2.27	2.26	2.28	1.99	1.99	3.44
2005	5.84	4.22	3.37	2.51	2.51	2.53	2.24	2.24	3.53
2010	5.78	4.26	3.46	2.70	2.69	2.73	2.44	2.44	3.59
2017	5.86	4.45	3.71	3.02	3.01	3.04	2.77	2.77	3.78
SDG&E									
1995	6.44	6.32	5.31	2.71	2.74	n/a	2.18	2.18	4.01
1997	6.88	6.18	4.72	3.32	3.32	n/a	3.07	3.07	4.56
2000	6.24	5.55	4.11	2.60	2.60	n/a	2.39	2.39	3.89
2005	6.15	5.51	4.18	2.80	2.80	n/a	2.59	2.59	3.78
2010	5.98	5.38	4.18	2.94	2.94	n/a	2.74	2.74	3.76
2017	5.92	5.37	4.31	3.21	3.21	n/a	3.03	3.03	3.90

Notes:
- 1995 prices are historical values.
- 1997 prices are based on partial 1997 supply and price data.
- 2000 and subsequent year prices are forecasted.
- Adopted March 18, 1998 by the California Energy Commission for the ***Fuels Report***.

Sensitivity Analysis

Although the forecast is based on a “most likely” perspective of market expectations, it is important to recognize the many uncertainties surrounding the competitive natural gas marketplace. To address this critical issue, staff performed a number of sensitivity cases to study how various assumptions could impact the results of the basecase projections. Sensitivity cases addressed the power generation market, resource availability, technology advances, overall demand, and market structural changes.

Perhaps, the greatest uncertainty in today's natural gas market concerns future natural gas demand for electricity generation throughout the United States. In California, for example, the utility companies are divesting their fossil fuel-fired generation facilities while, at the same time, new power plants are being proposed to be constructed within the state. While some of the divested power plants may continue as 'must-run' facilities, there is still uncertainty regarding whether the new proposed facilities will replace existing plants or serve incremental power to meet the state's needs. To analyze this issue and also consider the impact of power generation changes throughout the U.S., several sensitivities were run with different assumptions about the level of natural gas demand. Results indicate that an increase in total U.S. natural gas consumption of nearly 20 percent above the basecase levels, increases Lower 48 average wellhead prices by 22 percent above basecase projections by 2019.

Sensitivities focusing on California studied the impacts of assumptions, such as retiring older fossil fuel-fired power plants, replacing imports of electricity by more efficient in-state generation facilities, and advancing the retirement of some nuclear-powered generation capacity in the state. These assumptions cover a range of 20 percent above and below basecase demand assumptions for power generation by the end of the forecast horizon. This results in a moderate variation of natural gas prices at the State's border, being less than 10 cents per MCF compared to basecase projections by the end of the forecast horizon.

Another area where uncertainty in demand exists is the penetration of natural gas as a transportation fuel. While progress on bringing in natural gas powered vehicles (NGV) has been slower than anticipated, the potential exists to convert many fleet vehicles, trucks or buses to run on natural gas. A sensitivity case was designed to capture this effect by assuming a significant increase in natural gas use in NGVs. A maximum incremental demand of 1.9 TCF was assumed to be consumed by NGVs, which is equivalent to converting nearly 20 million vehicles in the Lower 48 states to use natural gas as fuel. This case shows that the wellhead price rises by around 13 cents per MCF by the year 2019. A second case was run to test the impacts if in addition to the NGV use, other end-use technologies were commercialized to use natural gas, increasing the incremental demand by nearly 4 TCF by the end of the forecast horizon. This case shows a wellhead price increase of around 30 cents per MCF above basecase projections.

Several other sensitivity cases covering aspects of resource estimates, technology impacts and market structural changes were also run and are described in detail in the Outlook.

Finally, several individual sensitivity cases were integrated to provide assumptions for a high price case and a low price case. These two cases were generated to provide an upper and lower bound on the direction of future natural gas prices. The high price case generated wellhead prices that are 50-75 cents per MCF higher than the basecase over the forecast horizon. In contrast, the low price case produced prices 40-60 cents per MCF lower than the basecase.

In conclusion, the analysis documents a future natural gas market that will be stable over the long term with plentiful supplies at adequate prices. While market conditions and increasing competition in all sectors of the market may result in more volatile (short-term) pricing, the same competitive forces will provide consumers the level of options they desire and provide overall benefits to all consumers. As has been experienced in the past, the market will find ways to ensure that natural gas will be available on demand to consumers either through increased capacity of existing pipelines or by building new pipelines. While the pipeline network is integrated, key expansions of segments and interconnections of the major corridors can achieve higher deliverability without adding new or major pipelines. Of special importance is the creation of natural gas hub centers which increase utilization of existing capacity through streamlining capacity utilization and exchange transactions. Further, programs such as capacity release help in utilization of unused capacity held by various shippers which would otherwise be stranded.

INTRODUCTION

Section 25310(a) of the California Public Resources Code requires the California Energy Commission (Commission) to prepare a biennial forecast of natural gas prices, supplies, and demand for California. The current forecast supports the natural gas market chapter of the ***Fuels Report***, a biennial publication to be submitted to the Governor and the Legislature describing emerging trends and long-range forecasts for a variety of fuel sources. It is also used extensively outside the Commission by other state agencies, local distribution utilities, pipeline companies, energy service providers, and others.

The ***1997 Natural Gas Market Outlook*** provides a forecast of natural gas prices and supplies for the 20-year period beginning in 1999. The forecast is the product of three distinct components. Phase one entails determining the price of natural gas delivered to the California border from several producing regions. Staff uses the North American Regional Gas (NARG) model, which calculates an equilibrium solution for supply, demand, and prices throughout North America over a 45-year time horizon. Phase two consists of an off-line analysis to determine a border price for different customer sectors throughout California. The final phase involves determining end-use prices by allocating each California gas utility's annual revenue requirement among the various sectors in each natural gas service territory. Specific details about the NARG model and the methodologies associated with developing the forecast are included in the remainder of this report.

The ***1997 Natural Gas Market Outlook***, is organized into six sections. Section I describes the basic structure of the NARG model and the underlying assumptions used to generate the basecase natural gas price and supply forecast. Specific attention is given to the development of natural gas resource cost curves and enhancements to the NARG model structure. Section II provides the results of the basecase forecast, with the California end-use price forecast detailed in Section III. Section IV considers sensitivities of changing individual parameters on the basecase results. An integrated market analysis of several sensitivities is described in Section V.

The final section of this report is a new feature of this and future reports which focuses on specific issues that impact the natural gas marketplace. In this report, staff discusses the importance of market centers, specifically looking at price differentials between regions and how they are expected to change during the forecast period.

Tabular details about the data assumptions used in the forecast are provided in the text of this report and a series of Appendices. Detailed California end-use price forecasts by utility service area are also documented in the Appendices.

I. NARG MODEL STRUCTURE AND ASSUMPTIONS

The North American Regional Gas (NARG) model has been used by the Commission to forecast natural gas prices and supplies since 1989. It is a generalized equilibrium model that simultaneously solves for supply, demand, and price equilibrium for a user-specified number of supply and demand regions over a 45-year time horizon. The supply and demand regions are connected by a series of pipeline corridors, creating an integrated natural gas infrastructure across the U.S., Canada and Northern Mexico.

A major feature of the NARG model is its flexibility to add or delete pipelines, supply regions, and demand regions. Capacity on any pipeline can be adjusted at a specific time in the future by the user, or alternatively, by the model as capacity additions become economically viable. Transport rates and shrinkage factors can also be modified by time period. Changes can also be made to resource assumptions, affecting the price and availability of a resource at a given point of a forecast. Demand assumptions can also be modified to make demand elastic or inelastic to price. Staff forecasts assume an inelastic demand, subject to fuel switching between natural gas and fuel oil.

A new feature added to the NARG model is the ability to account for reserve growth (or reserve appreciation) over time. The model allows the user to input a certain growth percentage estimate for each resource cost curve in the model that reflects the rate at which proved reserves and undiscovered resources grow over time. Staff's work to date suggests that these growth rates have a dramatic effect on both prices and production.

The addition of the reserve appreciation parameter fundamentally changes the economics of the NARG model. Previously, the model assumed ultimate depletion of natural gas resources, an assumption derived from Hotelling resource exhaustability theory. The new version of the model, while still based on Hotelling economics, minimizes the depletion effects .

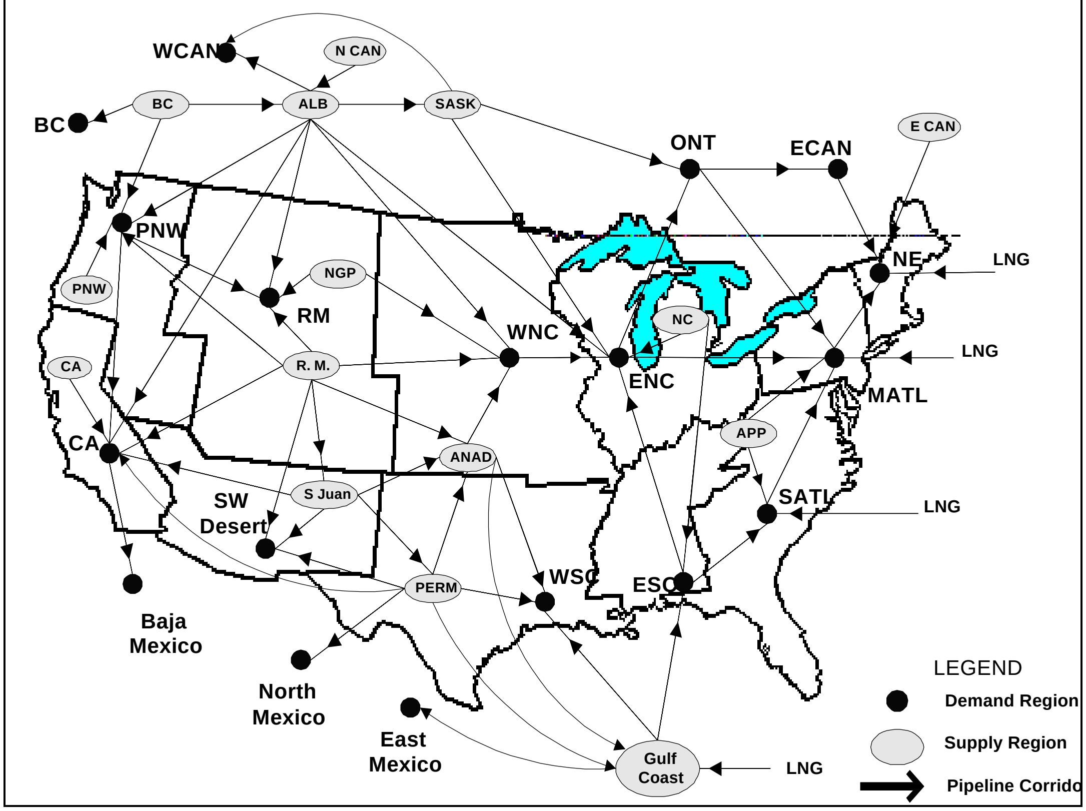
Staff's latest version of the model contains 18 supply and 19 demand regions, plus the ability to import liquefied natural gas from abroad (Table 1). Within each supply region are multiple resources, reflecting different types of conventional and unconventional formations. The U.S. demand regions largely correspond with U.S. census regions.

A schematic representation of the supply and demand regions is presented in Figure 1. The solid circles represent the demand regions while the shaded ovals represent supply regions. Figure 2 shows the detailed structure for California. The state is divided into four demand regions: Pacific Gas and Electric (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas and Electric Company (SDG&E), and the enhanced oil recovery (EOR) regions.

TABLE 1
SUPPLY AND DEMAND REGIONS INCLUDED
IN COMMISSION VERSION OF NARG MODEL

Supply Regions		Demand Regions	
Alaska - North	North Central	British Columbia	New England
Alaska - South	Northern Canada	California - EOR	Ontario
Alberta	Northern Great Plains	California - PG&E	Pacific Northwest
Anadarko	Pacific Northwest	California - SoCalGas	Rocky Mountains
Appalachia	Permian	California - SDG&E	South Atlantic
British Columbia	Rocky Mountains	Eastern Canada	Southwest Desert
California - Northern	Saskatchewan	East North Central	Western Canada
California - Southern	San Juan	East South Central	West North Central
Eastern Canada		Mexico	West South Central
Gulf Coast		Middle Atlantic	

Figure 1
CEC Representation of NARG Network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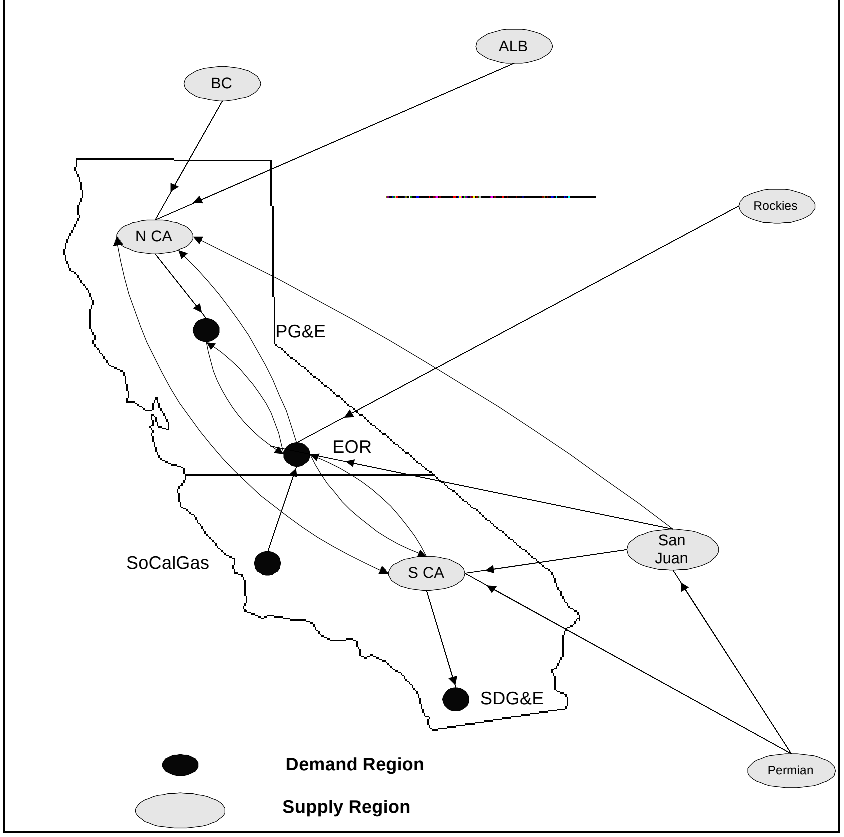
WSC
ESC
PERM
Baja
Mexico
North
Mexico
LEGEND
East
Mexico
Gulf
Coast
LNG
● Demand Region
Supply Region
Pipeline Corrido

Figure 2
NARG Network - California



Natural Gas Supply Assumptions

The natural gas resource base and the costs associated with finding, developing, and producing the gas are the most important factors in the development of the natural gas price and supply forecast. Wellhead price and production estimates for each producing region in the NARG model are calculated from a set of resource cost curves contained in the database. Each curve contains data specifying the level of natural gas proved reserves and resource potential, capital and operating costs associated with producing those resources, and the production profile.

Staff performed a comprehensive reassessment of the resource cost curves during the development of this outlook. A complete set of cost curves used in the analysis is provided in Appendix A. The current NARG model database includes 88 active resource cost curves in the continental U.S., Alaska, and Canada. For this ***Fuels Report*** cycle, staff's work focused on cost curves in the Lower 48. With the exception of two new cost curves in British Columbia and Eastern Canada, Canadian cost curves were left unchanged although capital and operating costs were adjusted from 1993 to 1995 dollars. Alaska curves remain identical to those used in the last forecast.

Staff significantly enhanced the level of detail associated with the resource assumptions in the Lower 48. With respect to conventional resources, staff increased the number of curves from 21 in the ***1995 Natural Gas Market Outlook*** to 38. The new curves coincide with the provinces outlined by the US Geological Survey (USGS) and the Minerals Management Service (MMS) in their respective 1995 National Assessments.

Equally important are the changes made to the unconventional resource base. Perhaps the greatest change in the structure of the resource cost curve database applies to coalbed methane potential. In the past, staff included any coalbed methane resources outside the San Juan Basin in the conventional resource database. Responding to our commitment to carefully investigate the outlook for coalbed methane production, the database now includes 17 coalbed methane cost curves across eight distinct supply regions.

Changes were also made to refine the estimate of tight sands resources. The present report contains 13 tight sands cost curves in six regions. Tight gas resource potential in the Permian and Anadarko basins assumed in the 1995 report was eliminated, based on USGS assumptions that those resources are contained in deep conventional formations. In addition, the NARG model database now includes seven cost curves that treat Devonian shale from the Appalachian supply region, Antrim shale in the Michigan Basin, and Barnett shale in the Fort Worth Basin.

Different from past reports, resource cost curves in the NARG model no longer distinguish between resource potential in shallow and deep formations. Staff aggregated estimates from both formations due to the lack of proved reserve data by depth.

Except for federal offshore estimates of resource potential, which were part of MMS' ***An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf***, the data used to generate the resource cost curves was provided exclusively by the U.S. Geological Survey (USGS). This is the same data used to support the USGS ***1995 National Assessment of United States Oil and Gas Resources***. The methodology employed by the USGS to develop the resource data is presented in three reports discussing the agency's conventional and unconventional (coalbed methane, tight sands, and shale) estimates (USGS Open File Reports 95-75A, 97-75F and 95-75H).

Methodology Used to Generate the Resource Cost Curves

Staff performed several tasks to convert the USGS data into a NARG model-usable format. In all cases, the data was sorted using capital costs as the primary determinant. The figures were then converted from 1993 dollars to 1995 dollars to arrive at an adjusted capital cost. Operating costs were further adjusted by adding gathering and processing costs to account for the costs of moving gas from the wellhead to the interstate pipeline receipt point. Total gathering and processing costs range from 16-43 cents per MCF, depending on the supply region.

Recognizing that some natural gas sold in the market is associated, staff assumed that 75 percent of the associated resource potential identified by USGS is potentially salable, with the remainder used for oil recovery operations. The associated resource potential was then added to the nonassociated curves, spread across each line of the cost curve on a pro rata basis.

The following two tables illustrate how staff derived cost curves from the USGS analysis. The example reviews the creation of a conventional cost curve for the Uinta-Piceance Basin of the Rocky Mountains. Table 2 presents the raw data obtained from USGS. Two factors are evident from the table. First, most of the resource potential is located in shallow drilling formations (less than 5,000 feet). Also, deeper formations in the Uinta-Piceance Basin require higher capital costs and are, therefore, more expensive to produce.

TABLE 2
RESOURCE POTENTIAL COST PROFILES
UINTA-PICEANCE BASIN (CONVENTIONAL)

	0-5,000 Drilling Depth			5,000-10,000 Drilling Depth		
Field Size	Reserves (MMCF)	Capital Cost (1993$/MCF)	Operating Costs (1993$/MCF)	Reserves (MMCF)	Capital Cost (1993$/MCF)	Operating Costs (1993$/MCF)
1	109,774	1.57	1.83	30,480	2.09	2.58
2	131,370	1.03	1.47	37,311	1.29	1.84
3	149,452	0.75	1.20	39,619	0.86	1.49
4	175,234	0.59	1.00	45,660	0.62	1.17
5	173,578	0.47	0.86	34,952	0.46	0.96
6	205,288	0.36	0.77	37,902	0.32	0.74
7	334,310	0.30	0.70	67,561	0.25	0.65
8	408,475	0.26	0.60	95,038	0.20	0.52
9	334,148	0.22	0.51	90,513	0.16	0.43
10	122,801	0.19	0.51	36,205	0.12	0.35
	10,000-15,000 Drilling Depth			Drilling Depth Greater Than 15,000		
1	3,114	9.10	2.36	448	29.44	2.65
2	3,964	5.12	1.61	526	14.57	1.63
3	3,651	3.18	1.13	617	8.55	1.14
4	3,470	2.08	0.83	729	5.32	0.81
5	2,421	1.41	0.53	850	3.45	0.53
6	807	0.88	0.44	972	1.98	0.43
7	1,291	0.62	0.39	1,620	1.33	0.29
8	1,614	0.44	0.28	1,943	0.90	0.21
9	1,291	0.32	0.21	1,943	0.62	0.15
10	1,291	0.23	0.15	1,296	0.43	0.11

Source: US Geological Survey, in support of the USGS 1995 National Assessment.

In generating the cost curve, all of the data points were sorted based on capital cost first, operating costs second, and resource potential third. The capital and operating cost estimates were both multiplied by 4.53 percent to adjust the costs from 1993 dollars to 1995 dollars, the base year used in the NARG model for pricing.[1] Per unit compression and operating costs were subsequently added to the operating cost data to arrive at a final operating cost to produce the gas at the wellhead and transport the gas to the interstate pipeline network. Cost estimates will be addressed in greater detail later in this section.

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[1] The 4.53 percent equals the Gross Domestic Product deflator index developed for the ***1996 Electricity Report***. Assuming 1993 is 100.0, the 1995 index is 104.53.

Table 3 presents the Uinta-Piceance basin conventional resource cost curve used in the NARG model. The actual curve is contained in the last three columns. An adjustment is shown in Columns 1 and 2 to reflect the availability of associated gas in the basin. USGS estimated 1.737 TCF of associated natural gas available in the basin. Staff assumed that 25 percent is used for oil recovery operations, with the remainder available to be marketed. The remaining 1.303 TCF was then added to the nonassociated cumulative reserve profile on a pro rata basis across each line of the cost curve.

TABLE 3
NATURAL GAS RESOURCE COST CURVE
UINTA-PICEANCE BASIN (Conventional)

Nonassociated Cumulative Reserves (TCF)	Associated Cumulative Reserves (TCF)	Total Cumulative Reserves (TCF)	Capital Cost ($/MCF)	Operating Cost ($/MCF)
0.000	0.000	0.000	0.13	0.72
1.156	0.559	1.715	0.27	0.98
1.735	0.839	2.574	0.38	1.16
1.946	0.941	2.888	0.49	1.25
2.170	1.050	3.220	0.65	1.58
2.494	1.206	3.700	1.08	1.89
2.645	1.279	3.924	1.64	2.27
2.694	1.303	3.996	3.32	2.30
			Proved Reserves	0.543 TCF
			Reserves-to-Production Ratio	10.0 Years

The 0.543 TCF proved reserve estimate for the region was derived using the ratio of actual 1994 conventional natural gas production in the Uinta-Piceance Basin to total conventional production in the Rocky Mountain supply region.[2] Using this approach, conventional proved reserves estimates for the Uinta-Piceance Basin represent approximately one-fourth of all conventional proved reserves in the region. The 10.0 reserve-to-production (R/P) ratio is simply the ratio of Rocky Mountain conventional production in 1994 compared to year-end 1993 proved reserves.

Also included in the cost curve, but not shown in Table 3, is an adjustment that the NARG model makes to account for proved reserve and potential resource appreciation. Reserve appreciation (or inferred reserves), which will be described later in this section, is defined by USGS to be the difference between proved reserves in known fields and the remaining recoverable resources in known fields. Staff assumed that proved reserves in the Uinta-Piceance supply basin appreciates at 1.5 percent per year, after accounting for annual production, through the forecast period. No appreciation in potential resources was assumed.

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[2] The Rocky Mountain supply region includes the Great Basin, the Uinta-Piceance Basin, the Paradox Basin, the Wyoming Overthrust Belt, Southwestern Wyoming (Green River Basin), and the Denver Basin. Other Rocky Mountain regions not mentioned are included in the Northern Great Plains supply region.

Natural Gas Resource Estimates

Proved Reserves

Staff estimates approximately 152 TCF of proved reserves in the Lower 48 at the end of 1993. Approximately 40 percent of the total was located in the Gulf Coast, with another 19 percent in the Anadarko region. The estimates shown are based on EIA figures provided in its ***U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1994 Annual Report.*** EIA's estimate is approximately 10 TCF higher than the staff estimate, due to staff's use of proved reserve data from the Alaska Department of Natural Resources and the California Department of Conservation[3] for Alaska and California, respectively.

Table 4 disaggregates proved reserve estimates by producing basin and resource type. Three-quarters (114 TCF) of the total is found in conventional formations, with the Gulf Coast and Anadarko regions containing the largest shares. Approximately 38 TCF of the reserves are located in unconventional formations among seven major supply regions. The San Juan and the Rocky Mountain basins dominate the amount of unconventional reserves in inventory in the Lower 48.

TABLE 4
PROVED RESERVE ESTIMATE BY SUPPLY REGION (YEAR-END 1993)
Trillions of Cubic Feet

Supply Region	Conventional	Coalbed Methane	Tight Sands	Shale	Total
Anadarko	27.977	0.110	0.000	0.000	28.087
Appalachia	0.236	0.810	4.580	1.380	7.006
California	4.613	0.000	0.000	0.000	4.613
Gulf Coast	55.348	1.237	2.978	0.000	59.563
North Central	0.993	0.000	0.000	1.010	2.003
Northern Great Plains	2.149	0.000	0.000	0.000	2.149
Permian	14.343	0.000	0.000	0.120	14.463
Rocky Mountains	4.897	0.240	9.891	0.000	15.028
Pacific Northwest	0.028	0.000	0.000	0.000	0.028
San Juan	3.150	7.820	7.660	0.000	18.630
Total - US Lower 48	113.734	10.217	25.109	2.510	151.570

The unconventional estimates are based on work performed by Advanced Resources International (ARI) in support of the USGS assessment. For additional information, see the ARI series of articles on unconventional resources published in the December 1995 and January 1996 ***Oil and Gas Journal.***[4] ARI also provided testimony at an August 1996 resource evaluation hearing. Staff's unconventional resource estimate is approximately seven TCF below that of ARI; however, the difference is included as part of the conventional proved reserve estimate, consistent with the geologic plays provided to staff by USGS.

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[3] For more information, see California Department of Conservation, ***1994 Annual Report of the State Oil and Gas Supervisor;*** and Alaska Department of Natural Resources, ***Historical and Projected Oil & Gas Consumption***, 2/94 for reserves and 3/95 for production.

[4] See the following Oil & Gas Journal articles: 1) *How Unconventional Gas Prospers Without Tax Incentives*, 12/11/95, p. 76-81, 2) *Technology Spurs Growth of U.S. Coalbed Methane,* 1/1/96, p.56-62, 3) *New Basins Invigorate U.S. Gas Shales Play*, 1/22/96, p.53-58, and 4) *Tight Sands Gain as a U.S. Gas Source*, 3/18/96, p. 102-107.

Potential Resources

Staff assumes 639 TCF of resources potentially available from undiscovered formations. The estimates are based on data provided by USGS and MMS. Staff estimates 274 TCF of potential resources in conventional formations with another 365 TCF of unconventional resources in the Lower 48. The Gulf Coast contains the largest share of conventional resources with the Rocky Mountains maintaining the largest share of unconventional potential resources. A summary of resource potential by basin and resource type appears in Table 5.

TABLE 5
POTENTIAL RESOURCE ESTIMATE
Trillions of Cubic Feet

Basin	Conventional	Coalbed Methane	Tight Gas	Shale	Total
Anadarko	18.127	5.008	0.000	0.000	23.135
Appalachia	2.389	14.309	27.145	25.876	69.719
California	18.920	0.000	0.000	0.000	18.920
Gulf Coast	186.052	2.308	5.770	0.000	194.130
North Central	3.227	1.611	0.000	19.293	24.131
Northern Great Plains	7.177	1.904	44.543	0.000	53.624
Permian	17.152	0.000	0.000	0.000	20.418
Rocky Mountains	18.249	16.349	134.256	0.000	168.854
Pacific Northwest	1.140	0.698	12.091	0.000	13.929
San Juan	2.040	29.703	20.737	0.000	52.480
Total - US Lower 48	274.473	71.890	244.542	48.435	639.340

Reserve Appreciation

A new resource category used by staff for the first time is proved reserve appreciation. Proved reserve appreciation is defined as the additional resource expected to be added to reserves due to extension of known fields, reserve revisions, and improved recovery techniques.[5] As emphasized in the introduction, the NARG model now has the capability to account for reserve growth (or reserve appreciation) over time. This capability fundamentally changes the economics of the NARG model since depletion effects, a long-standing assumption derived from Hotelling resource exhaustability theory, are minimized. In terms of how the feature is utilized in NARG model, reserve appreciation is applied by inputting a certain growth percentage estimate for each resource cost curve in the model that reflects the rate at which proved reserves and undiscovered resources are thought to grow over time. In this analysis, no growth in potential resources was considered.

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[5] Source: ***1995 National Assessment of United States Oil and Gas Resources*** , U.S. Geological Survey Circular 1118, pages 4-5.

Given the large impact that reserve appreciation has in the NARG model, comments made by interested parties on the results of staff's April 1997 preliminary forecast focused on the assumed reserve growth percentages. While noting that the inclusion of reserve appreciation is a major improvement to the NARG model, parties criticized staff for assuming a constant rate of reserve growth over time. Most parties also agreed that staff's assumed percentages were too optimistic.

Two expert witnesses were retained to address these concerns. One witness focused on reserve growth in Canada while the other concentrated on whether reserve growth estimates in the NARG model can support the levels of Gulf Coast and Rocky Mountain production generated in the preliminary forecast. Both separately concluded that reserve appreciation cannot effectively be performed on a straight annual percentage basis. They each recommended a vintaged approach, where appreciation rates are applied to various vintages of discovery. Additionally, they separately concluded that the ultimate reserve growth of an individual resource vintage is approximately three-fold, with the majority of the growth occurring during the first 4-5 years after discovery.

Staff agrees that additional work must be done to refine the manner in which the NARG model applies reserve appreciation. In the future, staff expects to incorporate additional code changes that will enable reserve growth to change for each of the model's time periods. As an interim measure, the expert witness' recommendations were incorporated into the analysis by substantially reducing the non-vintaged reserve growth estimates compared values used in the preliminary forecast.

Staff retained the use of the Energy Information Administration's 1989-1995 annual reports as the basis for reserve growth estimates in the current forecast. Responding to concerns of parties voicing an opinion on the preliminary forecast, staff placed a 1.5 percent reserve growth cap on the Rocky Mountains and a four percent reserve growth cap on all other regions in the Lower 48. Additionally, reserve growth for unconventional resources (tight sands, coalbed methane, shale) was set at 1.5 percent. Canadian reserve growth estimates were placed to two percent in the frontier region of Alberta, 1.5 percent in the rest of Alberta, and 1 percent for Saskatchewan. Reserve growth in other Canadian regions was set at 0.5 percent. Staff retained zero growth for California offshore production. Retention of the no growth estimate for this area is consistent with the continued push from environmental activists to halt California offshore production and a recent article stating that Chevron is seriously considering curtailing production in this region.[6]

Table 6 presents the reserve appreciation percentages used in this analysis. The table indicates that the Anadarko, Appalachian, Gulf Coast offshore, North Central, and Permian regions all reach the 4 percent reserve growth cap.

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[6] See "Chevron May Shut Some Offshore Rigs," Contra Costa Times, March 12, 1997.

TABLE 6
PROVED RESERVE APPRECIATION PERCENTAGES
(Annual Growth Rate per Year)

Supply Region	Description (If Needed)	Percent
Conventional Cost Curves		
Anadarko		4.00
Appalachia		4.00
California	Onshore	1.42
	Offshore	0.00
Gulf	Onshore - Eastern Gulf	2.46
	Onshore - All Others	2.80
	Offshore - State	4.00
	Offshore - Federal	4.00
North Central		4.00
Northern Great Plains		3.94
Pacific Northwest		0.00
Permian		4.00
Rocky Mountains		1.50
San Juan	San Juan Basin, Southwest Desert	0.84
	Raton Basin	0.84
Unconventional	Tight Sands, Coalbed Methane, Shale	1.50
Canadian Cost Curves	Alberta - Frontier	2.00
	Others	1.50
	British Columbia	0.50
	Saskatchewan	1.00
	Other Regions	0.50

Note:
Staff reviewed EIA reserve growth estimates by state for the 1989-95 period. The statewide data was then aggregated into producing regions based on staff's understanding of the location of each producing region in the model. A 1.5 percent cap was imposed on reserve growth in the Rocky Mountains and 4 percent for all other Lower 48 regions.

Table 7 provides an estimate of reserve appreciation and the percentage of the total resource base it represents. Throughout the Lower 48, 184 TCF (nearly 19 percent) of the total resource base can be attributed to reserve growth. Approximately 140 TCF applies to onshore resources with the remaining 44 available from offshore resources.

The greatest amount of reserve appreciation can be found in the Gulf Coast region, making up approximately one-quarter of the region's total resource. On a percentage basis, Anadarko and Permian supplies contain the greatest share of resource growth in their respective resource estimates (51 percent and 44 percent, respectively). In contrast, resource estimates in the Rocky Mountain region contain the smallest share of reserve growth (3.9 percent). Being a relatively immature producing region, the Rockies has several areas yet to be discovered, with the resources from those areas considered by geologists in the potential resource base.

TABLE 7
PROVED RESERVE APPRECIATION ESTIMATES THROUGH THE YEAR 2020

Supply Region	TCF	% of Region Resource
Anadarko	52.745	50.7
Appalachia	3.794	4.7
California	1.334	5.4
Gulf Coast	76.984	23.3
North Central	2.370	8.3
Northern Great Plains	3.946	6.6
Pacific Northwest	0.000	0.0
Permian	7.436	43.7
Rocky Mountains	27.073	3.9
San Juan	8.456	10.6
Total	184.139	18.9

The estimates shown in Table 7 represent the amount of reserve appreciation expected by the year 2020. The actual volume of reserve appreciation would be considerably higher if staff included reserve appreciation expected beyond the year 2020. This fact alone suggests that the reserve estimates provided in the analysis are conservative.

Natural Gas Resource Summary

As Table 8 illustrates, staff estimates 975 TCF of natural gas resource available currently in the ground, enough to satisfy current consumption trends for the next 50 years. The Gulf Coast is the region with the largest share of the resource potential, followed by the Rocky Mountains and the Anadarko region. Together, the three regions account for 65 percent of the total resource. California resources comprise less than 3 percent of the total.

TABLE 8
LOWER 48 NATURAL GAS RESOURCES

Supply Region	Proved	Potential	Reserve Growth	Total	% of Total
Gulf Coast	59.563	194.130	76.984	330.677	33.9
Rocky Mountain	15.028	168.854	7.436	191.318	19.6
Anadarko	28.087	23.135	52.745	103.967	10.7
Appalachia	7.006	69.719	3.794	80.519	8.3
San Juan	18.630	52.480	8.456	79.566	8.2
Permian	14.463	20.418	27.073	61.954	6.4
Northern Great Plains	2.149	53.624	3.946	59.719	6.1
North Central	2.003	24.131	2.370	28.504	2.9
California	4.613	18.920	1.334	24.867	2.6
Pacific Northwest	0.028	13.929	0.000	13.957	1.4
Total	151.570	639.340	184.139	975.049	100.0

Capital and Operating Costs

Most of the capital and operating cost assumptions were provided by USGS. For each nonassociated geologic area ("play" or "field") defined by the USGS, median per unit capital and operating cost information was provided for 18 different conventional field sizes and 11 unconventional field sizes. The data was divided into four depth categories (less than 5,000 feet; 5,001-10,000 feet; 10,001-15,000 feet; and more than 15,000 feet) and ordered based on resource potential, capital costs, and operating costs. For associated resources, resource potential was provided by geologic area without cost data.[7]

Capital costs include the "out-of-pocket" costs associated with drilling and completing a field, including the costs of drilling unsuccessful or dry holes.[8] USGS assumed that 40 percent of wells drilled in small fields and 20 percent of wells drilled in large fields were considered dry. Operating costs provided by USGS included only those costs applied to operating the well. Gathering and processing costs were added to the well operating costs based on Commission staff analysis outlined in the ***1995 Natural Gas Market Outlook***. Compression charges were assumed to be zero for all resources in the Lower 48.

Staff assumed a uniform $0.044 per MCF gathering charge to all Lower 48 supply regions. The estimate is equal to the previous report converted from 1993 to 1995 dollars. The original estimate was obtained from a 1992 publication entitled ***Ultimate Supply Potential and Supply of Natural Gas in Alberta***, published by the predecessor to the Alberta Energy Resources Conservation Board.

Processing charges used in the analysis range from $0.12 per MCF in the San Juan Basin to $0.425 per MCF in the South Louisiana region of the Gulf Coast. The data was compiled using information published by EIA in its ***1994 Natural Gas Annual*** and ***U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1994 Annual Report***. The 1994 average liquids extraction cost for the Lower 48 of $0.236 per MCF was first adjusted to 1995 dollars. Next, regional differences were determined by calculating a liquids extraction ratio for each region. The ratio represents the total amount of natural gas liquids extracted from the gas originally produced at the wellhead. The average processing charge was computed by multiplying the average $0.241 per MCF rate in 1995 dollars by the ratio determined for each basin. Table 9 summarizes the gathering and processing costs used by region for the Lower 48.

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[7] Associated natural gas is produced concurrently with the production of oil. Hence, the price of oil dictates whether the gas is produced.

[8] A rate of return on the capital investment was not incorporated into the capital cost profile since the NARG model generates one based on user inputs. Staff assumed a 10 percent real return on equity and a 2.5 percent real return on debt.

TABLE 9
GATHERING AND PROCESSING COST ADDERS
TO OPERATING COSTS BY SUPPLY REGION
(1995$ per MCF)

NARG Supply Region	Gathering	Processing	Total Adder
Anadarko	0.044	0.197	0.241
Appalachia	0.044	0.131	0.175
California - Onshore	0.044	0.264	0.308
California - Offshore	0.044	0.264	0.308
Gulf - Offshore	0.044	0.202	0.246
Gulf - West Onshore	0.044	0.216	0.300
Gulf - East Onshore	0.044	0.280	0.330
North Central	0.044	0.386	0.430
Northern Great Plains	0.044	0.212	0.256
Pacific Northwest	0.044	0.241	0.285
Permian	0.044	0.175	0.219
Rocky Mountains	0.044	0.309	0.353
San Juan	0.044	0.120	0.164

Note: Canadian gathering and compression costs were built into the resource cost curves provided by the Canadian National Energy Board.

Production Decline Profiles

One factor directly affecting the cost of a resource is the rate at which the gas is produced from a given resource type and region. As a result, each resource cost curve contains a “production decline profile.” Two types are used in the NARG model. The first is the exponential decline profile, which uses a reserves-to-production (R/P) ratio and assumes a minimum ratio of proved reserves to annual production. Alternatively, specific production profiles can be used, which allow the NARG model user to specify levels of production over time from any specific type of resource.

USGS provided production profiles for each unconventional play, based on the median well in the assessed region. All coalbed methane gas plays assume a 25-year production life while tight gas plays produce up to 50 years. Similar data was not available for conventional resources, requiring staff to use the R/P approach. R/P ratios for various supply regions in the staff analysis are aggregated in Table 10. Specific R/P ratios for each individual cost curve can be found in Appendix A.

TABLE 10
R/P RATIOS FOR CONVENTIONAL
RESOURCE COST CURVES

NARG Supply Region	Proved Reserves 12/31/93 (BCF)	1994 Production (BCF)	R/P Ratio
Anadarko	24105	2563	9.4
Appalachia	236	4	53.7
California - Onshore	2876	253	11.4
California - Offshore	1737	58	29.9
Gulf - Offshore	27296	4942	5.5
Gulf - West Onshore	17542	3070	5.7
Gulf - East Onshore	8778	885	9.9
North Central	993	59	16.9
Northern Great Plains	2585	201	12.8
Permian	14343	1791	8.0
Rocky Mountains	4897	489	10.0
San Juan	3150	24	131.3
Regions with Unchanged R/P Ratios			
Alaska			10.0
Pacific Northwest			10.0
Canada			10.0

Note: Although R/P ratios exceed 35 years in several cases, a ceiling R/P ratio of 35 years was used in the analysis. Estimates in the NARG model exceeding that threshold often create convergence problems.

Technology Impact on Costs for Potential Resources

The methodology employed to develop technology impact parameters for the 1993 and 1995 ***Natural Gas Market Outlooks*** was retained for this forecast. In those reports, staff concluded that the relative cost of developing and producing natural gas is declining and will continue to decline as existing drilling technologies are enhanced and new technologies are developed.

Over time, technology enhancements are expected to reduce the capital costs of production shown for each resource cost curve by 32-52 percent, depending on the supply region. This includes a 6 percent reduction for 3-D seismic drilling, a 14 percent reduction for implementing slim hole drilling, and a 30 percent reduction for new drill bit technologies. An additional 20 percent reduction was also applied to account for cost reductions due to new technologies, such as laser drilling which are not yet in place. Drilling costs to develop reserves are assumed to drop at an annual rate of 10 percent of the remaining potential reduction.

Appendix B shows the potential impact that each new technology is expected to have on drilling costs for each resource type. The last column of the Appendix represents the assumed lower bound for the potential reduction (percent) in capital costs used in the NARG model.

The primary source of drilling data used in the staff technology assessment came from the American Petroleum Institute's ***Joint Association Survey on 1994 Drilling Costs***, published in November 1995. The 20 percent future technology reduction was based on recommendations provided by Gas Research Institute staff at a May 1996 meeting of the NARG User Group.

Natural Gas Demand Projections

Staff relied on a variety of sources to generate a natural gas demand forecast. California natural gas demand projections were performed by the other two Commission offices comprising the Energy Information and Analysis Division. Residential, commercial and industrial customer demand assumptions were developed by the Demand Analysis Office in its 1998 Basecase Energy Outlook. Detailed documentation of these results will be available on the Commission's web page (www.energy.ca.gov).

The Electricity Analysis Office derived electric generation demand estimates using electric generation capacity expansion plan results.[9] The demand data for 1994 represent actual consumption and were obtained from the California energy balance of gas production and consumption. Attachment C lists the demand for natural gas in the core market and the demand for natural gas plus competing oil in the noncore market for each demand region in California.

For all other regions in the continental United States, staff utilized Gas Research Institute's (GRI) ***Baseline Projection Data Book***, 1996 edition. Data were aggregated into core (non-switchable) and noncore (switchable) demand. Core demand with respect to the GRI data includes residential gas, commercial gas, natural gas vehicles (NGV), and 50 percent of industrial gas demand. Noncore demand includes the remaining 50 percent of industrial gas, and all electricity generation gas. It was assumed that natural gas can compete with oil in the electric generation sector outside of California and portions of industrial and commercial petroleum demand. Therefore, noncore projections also include oil used for electric generation, 25 percent of commercial oil, and an increasing percentage of industrial oil (20 percent in 1999, 30 percent in 2004, 40 percent in 2009, and 50 percent in 2014 through 2039).

Staff derived the Canadian natural gas demand estimate using Canadian Gas Association's ***Forecast of Domestic Natural Gas Demand: 1996-2010***. Forecasted data were provided by customer class for the six major Canadian provinces for the years 1995-1997, 2000, 2005, and 2010. Staff interpolated estimates for 1999, 2004, and 2009. Estimates from 2011-2019 were calculated based on the annual growth rate in demand from 1995 to 2010. Demand estimates beyond 2019 were assumed to increase at a constant 1 percent per year.

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[9] The electric generation forecast does not include changes regarding how the restructured electricity market will operate. Absent large investments in new or existing generation facilities, generation sources are unlikely to change much in the short-run. In the long-run, not much new generation is expected to be added until 2006, with large additions occurring outside California.

Staff placed 100 percent of residential and commercial requirements and 75 percent of industrial requirements for each Canadian demand region in the core sector. The remaining 25 percent of industrial demand and all electric generation requirements were allocated to noncore demand. These percentages were based on discussions with National Energy Board (NEB) representatives. Switchable fuel oil for industrial, electric generation, and petrochemical customers was also added to the noncore demand estimate, based on the Canadian Energy Research Institute's (CERI) ***North American Natural Gas Outlook: Basin-on-Basin Competition*** published in March 1996.

Mexican demand estimates were limited to three regions in Mexico located adjacent to the U.S. border (Baja, North, and East). Staff increased existing demand at an arbitrary 1 percent per year from recorded 1995 estimates. Using information provided by the EIA in its ***Natural Gas Imports and Exports*** report published in the second quarter of 1995, staff identified new facilities expected to consume natural gas during the forecast period. Demand at these new facilities was increased at 1 percent per year after the project startup date. Finally, development of a Mexican natural gas market infrastructure was assumed to enable Mexican production to satisfy 20 percent of requirements in the North and Eastern demand regions by 2019. Core and noncore distinctions were not addressed in this forecast.

Natural Gas Transportation Assumptions

Structural Enhancements to the NARG Model

Several changes were made to the NARG model to better reflect the natural gas transportation network in North America. The most significant change centered on disaggregating the West North Central/Mountain (WNC/MTN) demand region. The region was split in order to improve staff analysis of natural gas flow and price projections throughout the western United States. Other changes include "rolling in" the costs of the PG&E Gas Transmission - Northwest (PGT)[10] Original and Expansion pipelines, the creation of a Pacific Northwest demand region, the inclusion of Mexican demand in the basecase, and improved corridor representation for gas flowing to the northeast. A brief description of each change follows.

- **Disaggregation of the WNC/MTN Region into Three Regions**
  Southwest Desert Demand Region - a new region in the model comprising Arizona, New Mexico, and Southern Nevada. This region better represents natural gas flows on the El Paso and Transwestern systems from the San Juan and Permian Basins. Included for the first time, are direct links to demand centers in Arizona, New Mexico, and Las Vegas.

  Rocky Mountain Demand Region - a new region in the model including Colorado, Wyoming, Utah, Idaho, and Montana. Within the region itself are four separate demand nodes for each state, Colorado and Wyoming being combined. Staff completed this change to more accurately estimate market competition between producers in the Rocky Mountains and Canada.

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[10] PG&E Gas Transmission - Northwest was formerly known as Pacific Gas Transmission Company. For purposes of convenience, staff uses PGT as the acronym.

West North Central Demand Region - includes Kansas, Nebraska, North Dakota, South Dakota, Minnesota, Iowa, and Missouri. Capacity refinements were also made to the pipeline corridors linking the modified region with the Rocky Mountains, Anadarko, and East North Central (ENC) regions. Additionally, the link between the Anadarko and ENC sectors was eliminated to more accurately reflect flows from the Permian/Anadarko Basins to the midwest and allow competition with Rocky Mountain gas.

- **Addition of Pacific Northwest Demand Region**
  In conjunction with some of the work disaggregating the WNC/MTN region, staff added a new demand region comprising Washington, Oregon, and Northern Nevada. A Reno citygate was also created with new links representing the Paiute and Tuscarora Pipelines. The breakdown of Southern and Northern Nevada was based on review of pipeline-specific flow data from EIA and discussions with Southwest Gas Corporation, the primary distribution utility in Southern Nevada and owner of Paiute Pipeline in Northern Nevada.

- **PG&E Gas Transmission (PGT)**
  The PGT original and expansion lines have been combined into one pipeline link, with a transmission rate equal to $0.263 per decatherm. The rate was adopted by the Federal Energy Regulatory Commission (FERC) in mid-1996 in accepting a Settlement Agreement in PGT's 1994 general rate case proceeding (RP94-149). Between 1996 and 2001, shippers holding firm capacity on the original PGT line (primarily PG&E) pay 75 percent of the rolled-in rate, while expansion shippers pay approximately 125 percent of the rate. Given the long-term nature of the model, staff does not distinguish between the two rates in 1999, the first forecast period.

- **PG&E Backbone (Lines 400 and 401)**
  Lines 400 and 401 have been combined in the NARG model. The combined corridor, however, was divided into three segments to account for transport rates and capacities available to: 1) the core market on Line 400 (600 MMCF/D); 2) the noncore market on the rolled-in portion of Line 400/401; and 3) Southern California via Line 401 (600 MMCF/D). No constraint is applied to noncore market deliveries on Line 400/401.

- **El Paso Havasu Crossover Expansion and Southern System Flow Eastward**
  El Paso recently expanded the Havasu Crossover by 180 MMCF/D to allow several producers to flow gas from the San Juan Basin in Texas using the underutilized southern system mainline. A link was placed in the NARG model to allow gas to flow east from the San Juan Basin to Texas via the Havasu Crossover and the El Paso southern system. A transmission rate of $0.105 per MCF was placed on this link, equal to the per unit reservation charge incurred by customers flowing gas east on the southern system.

- **Mexican Demand**
  The current case marks the first time staff has included natural gas demand from Mexico in the basecase. Demand projections are limited to Mexican provinces along the international border, based on the assumption that southern regions in Mexico will continue to be served by Mexican gas supplies.

- **Eastern Canada Links**
  Recognizing the development of natural gas fields off of Nova Scotia and increased demand for gas in New England, staff added a direct link between Eastern Canada and New England.

- **Miscellaneous Pipeline Corridor Enhancements**
  A new link from Raton Basin to Anadarko supply region was added to account for Colorado Interstate Gas Company connection from Southeastern Colorado.

  A link between East South Central to Mid-Atlantic demand region was eliminated to better represent interstate pipeline capacity along the eastern seaboard.

Pipeline Capacities

Staff updated pipeline corridor capacities in the NARG model using a variety of sources. From EIA, staff used three publications, ***Capacity and Service on the Interstate Natural Gas Pipeline System - 1990*** (1992), ***Natural Gas Annual - 1994***, and ***Energy Policy Act: Interim Report on Natural Gas Flows and Rates*** (1995). EIA also provided staff with workpapers exhibiting capacities and flows across state borders by pipeline in computer spreadsheet format.

Staff also relied heavily on a December 1994 Foster Associates study entitled ***Competitive Profile of Natural Gas Services***, various ***FERC Form 567*** 1993 and 1994 filings, pipeline company bulletin boards, and numerous discussions with industry participants. Canadian pipeline capacities were adjusted based on capacities published by the AGA in its September 1994 ***Gas Energy Review*** and conversations with various pipeline representatives.

Pipeline Transmission Rates and Discounting

Updated transportation rates for the pipeline corridors considered in the NARG model are provided in Appendix D. The rates used for the various corridors in the ***1995 Natural Gas Market Outlook*** are provided for comparison. When comparing current rates to rates used in previous reports, please note that the definition of some of the pipeline corridors may have changed due to structural enhancements to the NARG model. For example, the WNC to ENC corridor (without Northern Border) in the present forecast is $0.143 per MCF, $0.45 per MCF less than the price used in the ***1995 Natural Gas Market Outlook*** forecast. The difference can be attributed to the NARG model structural enhancements. The WNC-ENC corridor no longer includes pipelines transporting gas out of the Rockies supply region. Instead, these pipelines are now accounted for in the Rockies-WNC corridor.

Average pipeline transportation rates for the corridors in the model were based on conversations with pipeline representatives or on a review of rates published in pipeline tariff booklets. A constant base tariff is assumed for all pipeline corridors throughout the forecast horizon. However, similar to the ***1995 Natural Gas Market Outlook*** forecast, the actual rate may vary based on the utilization of the pipeline corridor. The rate multipliers or discounts used in the analysis are shown in Table 11. For pipelines with utilization rates at or above 85 percent, no discount is applied to the rate. Below 85 percent, the discount increases, up to a maximum of 50 percent. Multipliers are also attached to pipeline corridors that exceed 115 percent of full capacity availability. The maximum multiplier is four times the base tariff, which occurs when utilization is double the initial capacity assumption.

TABLE 11
UTILIZATION RATE MULTIPLIER USED IN THE NARG MODEL TO DETERMINE DISCOUNTS AND ADDERS

(As Percent of the As-Billed Rate)

	Utilization Rate percent (%)	**Standard Multiplier**
Discounted Portion of Curve	0-50	0.500
	65	0.650
	75	0.800
	85	1.000
	100	1.000
Adder Portion of Curve	115	1.000
	120	1.250
	130	1.594
	140	1.938
	150	2.281
	160	2.625
	170	2.969
	200+	4.000

Miscellaneous Assumptions

Initial Conditions

To generate a gas price and supply forecast, the NARG model requires a set of initial conditions which balance demand with supply for the specified start or “base” year. In the present forecast, gas flows during 1994 are input to the model as an equilibrium of balanced natural gas flows at each point in the model structure.

The entire energy balance was performed in-house by Commission staff. The California portion of the energy balance was compiled from several sources, primarily the ***1994 California Gas Report***. Demand data for non-utility EOR cogeneration capacity were based on the Department of Conservation, Division of Oil and Gas publication, ***80th Annual Report of the State Oil & Gas Supervisor***. The Commission's *Quarterly Fuel and Energy Report (QFER Form 10A)* provided data for California gas production transported directly to industrial and enhanced oil recovery facilities. Submittals to the Commission under the Petroleum Industry Information Reporting Act contain data for EOR steaming and oil burn.

For the rest of the Lower 48, staff relied heavily on workpapers supporting EIA's ***1994 Natural Gas Annual*** report. The workpapers contain information on natural gas flows across state and international boundaries identified by specific pipelines. Pipeline flows were then aggregated and assigned to individual transportation links or corridors in the NARG model. To determine the proper level of base year gas production, staff used EIA's ***U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*** 1994 report and a series of articles submitted by Advanced Resources International (ARI) to ***Oil & Gas Journal*** and testimony provided to the Commission at the August 1996 resource evaluation hearing.[11]

The data provided by EIA contain information on a statewide basis, with some disaggregation in Texas, Louisiana, California, Oklahoma, and New Mexico. Other areas required some method of allocating statewide production to the various producing basins. To translate statewide production into production estimates for the Arkoma, Anadarko, Gulf Coast, Northern Great Plains, Permian, Rockies, and San Juan regions, staff utilized 1993 production data by county for the following states: Arkansas, Colorado, Montana, Oklahoma, Texas, and Wyoming. The data were prepared by Dwight's Energy Services and furnished to staff by EIA. As an example, the state of Wyoming has 22 counties, 13 located in the Northern Great Plains supply region and nine in the Rocky Mountains supply region. Comparing county production for 1993, staff determined that 86.5 percent of the total production occurred in counties defined to be part of the Rocky Mountain supply region. Thus, that percentage of production in Wyoming was applied to base year Rocky Mountain estimates.

The Canadian portion of the energy balance was completed using several publications. A Statistics Canada publication entitled ***Gas Utilities - 1994*** provided information on base year demand and gas flows between provinces. The data were converted from thousand cubic meters to billion cubic feet and split between core and noncore demand markets. Direct sales reported in the publication were allocated equally to core and noncore nodes. Staff kept the level of switchable fuel oil at base year 1992 levels. Provincial production estimates were obtained from ***Gas Facts - 1994***, published by the American Gas Association, and discussions with CERI and NEB staff. Pipeline flows in and out of Alberta were obtained from an ***Oil & Gas Journal*** article reporting shipments on the NOVA system.[12]

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[11] See Footnote 4.

[12] See Oil and Gas Journal, *NOVA Gas Shipments Climb* , 2/19/96, p.22.

Owner/Producer Discounts

The "Owner's Discount Rate" is defined as "the rate used by the original owner of a resource deposit to discount cash flows resulting from the sale of leases to resource producers." Conversely, the "Producer's Discount Rate" is the required rate of return on equity for all investments made by gas producing companies. In the ***1995 Natural Gas Market Outlook***, staff used 6 percent for both discount rates. Toward the end of the ***1995 Fuels Report*** proceeding, an expert witness, retained by the Energy Commission, argued that staff should use a 10 percent producer's discount rate and 4 percent owner's discount rate. Although unable to incorporate his comments into the ***1995 Natural Gas Market Outlook*** forecast, staff adopted these recommendations as well as his recommended 2.5 percent cost of debt for the current analysis.

Time Frame

This ***Natural Gas Market Outlook*** gas price forecast uses 1994 as the base year. The NARG model generates forecast data in five-year increments starting from the 1994 base and ending with 2039. Although a 45-year forecast is generated, staff focuses on the 1999 to 2019 forecast period.

Dollars

All prices in this analysis are in constant 1995 dollars. The deflator series used for this conversion was developed for the ***1996 Electricity Report*** based on Gross Domestic Product. The deflator series used in the analysis is included in Appendix K.

Exogenous Fuel Prices

Several fuel price forecasts are exogenous inputs to the model.

- **Oil Price Forecast**
  The Commission's ***Delphi VIII Survey of Oil Price Forecasts***[13] is the source for oil price forecast. These oil prices are shown in Table 12 and were used for U.S. and Canadian oil price updates. The oil prices are lower than the ***Delphi VII Survey of Oil Price Forecasts*** used in the ***1995 Natural Gas Market Outlook***.

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[13] Since 1982, the Commission has conducted biennial surveys of oil price forecasts using a modified Delphi approach. Under this method, a panel of recognized energy experts is selected and surveyed for their most likely, high and low oil price forecasts considering contributions of numerous potential influences.

TABLE 12
DELPHI VIII SURVEY OF OIL PRICES

Year	Dollars per Barrel (1995$)	Dollars per MCF (1995$)
1994	15.40	2.73
1999	17.71	3.14
2004	18.84	3.35
2009	19.79	3.51
2014	20.53	3.65
2019	21.50	3.82
2024	22.66	4.02
2029	23.88	4.24
2034	25.17	4.47
2039	26.53	4.71

Source: California Energy Commission, ***Results of the Delphi VIII Survey of Oil Price Forecasts,*** P300-95-017B, March 1996**.**
Conversion Formula Used Above: $/Barrel/5.8 MMBtu/Barrel * 1.03 MCF/MMBtu.

The oil price forecast is used to determine the regional price of residual fuel oil or heavy fuel oil that competes with natural gas in the noncore market sector. The conversion from the input Delphi world oil price to regional fuel oil price is achieved through a multiplier that has been determined for each region, based on historical prices of fuel oil consumed in each region. In the model, this price is assumed to be representative for all noncore customers including the industrial and electricity generation sectors.

- **Backstop Price**
  The backstop price represents a price at which some technological breakthrough provides an unlimited supply of natural gas. Staff retained a constant $5.00 per MCF backstop price for the entire forecast period.

- **Liquefied Natural Gas (LNG) Facilities and Prices**
  The LNG price is designed to allow natural gas supplies from overseas to compete with Lower 48 and Canadian supplies. The cost of LNG in the model is a dummy variable equal to the estimated commodity cost plus tanker transportation and regasification at a border facility. The NARG model presently includes four LNG regasification facilities in the U.S., three along the Atlantic seaboard and one on the Gulf coast. While no specific facility additions are incorporated into the analysis, the NARG model does allow for expansion of existing facilities to occur, if required.

II. BASECASE OUTLOOK

The Commission's forecast of natural gas production and prices by region for North America over the 20-year forecast horizon (1999-2019) is provided in this section. It includes: 1) a basecase projection of wellhead production and prices, 2) supply and price availability at the California border, 3) an outlook for future pipeline expansion, and 4) an outlook for California production. A comprehensive discussion of the California end-use price estimate by customer class is provided in Section III.

Gas Supply Outlook and Trends

Natural gas supplies will remain plentiful for the next several decades. Staff estimates a total resource base (gas recoverable with today's technology) for the Lower 48 of 975 TCF, enough to satisfy current production levels for more than 50 years. This estimate is conservative, given that a significant portion of Canada's 420 TCF of gas will serve Lower 48 gas markets as well. Furthermore, improvements in exploration and drilling technologies will allow producers to access resources neither considered economically recoverable today nor part of the resource estimate.

While technical enhancements will continue to increase the size of the resource base, it is much less certain whether producers will be able to increase their production capacity to meet incremental demand. Several factors must be met during the long-term if production capacity is to increase. First, production from new wells must offset production declines from existing wells and increase by the level of incremental demand. Recent discussions in the natural gas industry have addressed concerns about whether drilling activity and the startup of new wells in key producing areas can offset reduced production from wells currently operating. In the Gulf Coast region, for example, some experts argue that new deepwater offshore production may simply offset declines throughout the rest of the region.[14]

Second, processing facilities and gathering, transmission, and distribution pipelines must be sufficient to take the gas from the wellhead to the burner tip. Rapid increases in drilling activity are useless if the gas is unable to be processed and placed in the pipeline network. As indicated later in this chapter, the Rocky Mountains will emerge as the second largest supplier of natural gas in the Lower 48. Unless pipeline capacity is constructed, gathering systems are developed, and processing capacity is increased, this emergence will not be possible. The same conclusion is true of the deepwater region of the Gulf Coast. Major increases in production are projected but cannot be realized in the absence of downstream facilities. While several pipeline projects appear to support future growth in the Gulf region,[15] it is less certain whether new facilities will improve prospects for Rocky Mountain production.

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[14] Energy ERA. "Gulf Coast Offshore Gas: Past, Present, and Future," *Natural Gas Analyst*, October 1997, p. 10.

[15] Ibid, p. 8.

Finally, a larger share of natural gas industry Research and Development (R&D) budgets must be devoted to technology development. Unfortunately, the trend for future R&D spending is headed down. During the past two years, Congress has indicated a preference to reduce exploration and production-related research by the Department of Energy. Additionally, the budget of the Gas Research Institute has been reduced significantly and will soon be funded on a voluntary basis.[16] These types of reductions, while not impacting technology advancements in the short-term, could impact the historical trend of technology advancements over the next 20 years.[17] Despite these concerns, the Commission's long-term supply outlook assumes that productive capability grows to meet incremental demand, pipelines are constructed if needed, and technology improvements continue at their current pace.

Staff expects Lower 48 production to increase from 17.1 TCF in the 1994 base year to 25.9 TCF in 2019 (Table 13). Producers in the Gulf Coast and Rocky Mountain regions will account for most of the increase during the next two decades. Gulf Coast producers, driven by the development of several major deepwater fields in the Gulf of Mexico, will increase production by nearly 60 percent to 14.4 TCF. Rocky Mountain production will almost triple to 3.3 TCF while its share of the Lower 48 market doubles. By the end of the 20-year forecast period, these two regions will account for more than two-thirds of all gas produced in the Lower 48.

In contrast to the strong production trends anticipated for the Gulf Coast and Rocky Mountains, the traditional producing areas of the Anadarko and Permian Basins will play a less significant role in meeting future end-use demand. Anadarko production is expected to drop 38 percent to 1.8 TCF while Permian production declines 16 percent to 1.3 TCF. The expected decline can be explained by the relative maturity of each producing region, which lessens the likelihood that new pools of natural gas will be found to replace developed pools with declining wellhead production.

Figure 3 compares Lower 48 natural gas production by resource type. Although conventional resources can be expected to account for the majority of gas production during the next 20 years, production from tight sands, coalbed methane, and shale formations will play a significant role in meeting future natural gas demand. Conventional sources, accounting for 83 percent of total Lower 48 production in the 1994 base year, is expected to decline to 73 percent as unconventional shares increase. Tight sands production, comprising 11 percent of the total in 1994, will increase its share to 15 percent by 2019. Production of natural gas from coalbed methane formations will increase from 5 percent in 1994 to 9 percent at the end of the forecast period. Staff projects that the market share of production from shale formations will increase from 1 percent to 4 percent during the same time period.

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[16] Smith, D.J. and Buskirk, H. "FERC Sends Decision on GRI to a Judge for Final Settlement," *Natural Gas Week*, November 17, 1997, p.10.

[17] Haas, M.R. "Upstream Sector Productivity: The Role of R&D in Gas Technology Development," *The 1997 Natural Gas Yearbook*, pp. 259-288.

TABLE 13
LOWER 48 AND CANADIAN PRODUCTION
(TCF PER YEAR)
BaseCase

Supply Region	1994	1999	2004	2009	2014	2019
LOWER 48						
Anadarko	2.890	2.435	2.452	2.175	2.172	1.797
Appalachia	0.531	0.679	0.995	1.056	1.273	1.466
California	0.311	0.257	0.341	0.343	0.375	0.388
Gulf Coast	9.135	9.529	10.545	11.732	13.110	14.417
North Central	0.186	0.507	0.611	0.667	0.720	0.763
Northern Great Plains	0.200	0.267	0.302	0.336	0.370	0.452
Pacific Northwest	0.003	0.010	0.019	0.033	0.051	0.082
Permian	1.677	1.727	1.923	1.825	1.588	1.414
Rocky Mountains	1.121	1.693	1.929	2.213	2.634	3.267
San Juan	1.074	1.737	1.998	2.069	2.017	1.882
Total: Lower 48	17.128	18.842	21.116	22.448	24.312	25.927
CANADA						
Alberta	4.033	4.980	5.507	5.971	6.469	6.838
British Columbia	0.569	0.792	0.897	0.831	0.794	0.801
Eastern Canada	0.282	0.000	0.055	0.112	0.149	0.149
Saskatchewan	0.000	0.251	0.159	0.126	0.100	0.104
Total: Canada	4.884	6.023	6.618	7.039	7.487	7.893

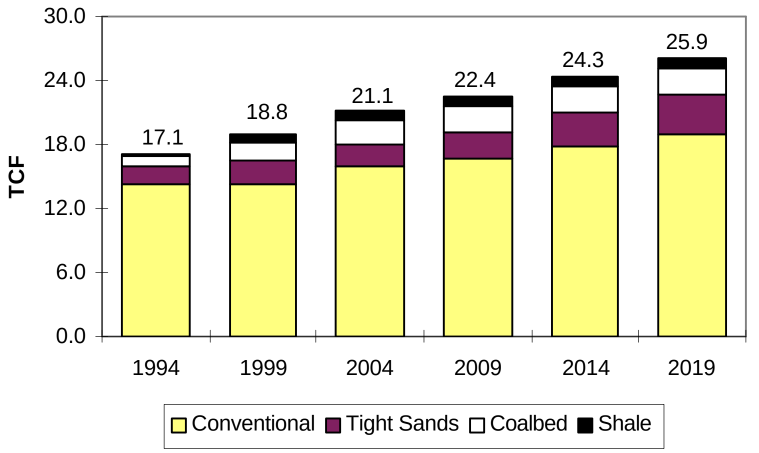


Figure 3
Lower 48 Production by Resource Type

In Canada, Alberta producers continue to provide the bulk of Canadian production. With the expected startup of Sable Island production off the Nova Scotia coast, production from Eastern Canada will begin to serve New England markets by 2004. Canadian production for all regions will increase by 1.9 TCF from 1999 to 2019, with about two-thirds of the additional supplies meeting new domestic demand. Canadian exports are projected to rise to 3.9 TCF in 2014 and remain at that level through the end of the forecast period.

Wellhead Prices

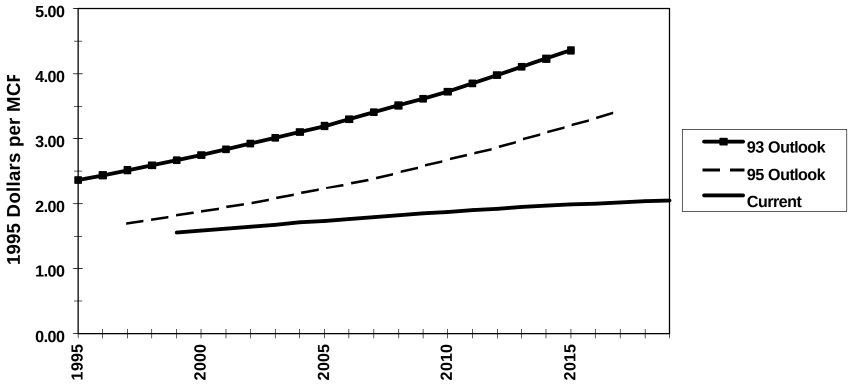
A comparison of natural gas prices by region and in the aggregate is shown in Table 14. For the Lower 48, the average price increases from $1.55 per MCF in 1999 to $2.05 per MCF in 2019, an increase of 1.4 percent per year (in 1995 dollars) on an average annual basis. In Canada, prices increase 2 percent per year in real terms from $1.10 per MCF in 1999 to $1.65 per MCF.

TABLE 14
LOWER 48 AND CANADIAN WELLHEAD PRICES
(1995$ PER MCF)
BaseCase

Supply Region	1999	2004	2009	2014	2019
LOWER 48					
Anadarko	1.63	1.82	2.03	2.19	2.36
Appalachia	2.18	2.32	2.51	2.60	2.70
California	1.84	2.01	2.19	2.39	2.58
Gulf Coast	1.58	1.74	1.87	1.98	2.04
North Central	1.80	1.87	1.94	2.01	2.06
Northern Great Plains	1.22	1.27	1.33	1.38	1.43
Pacific Northwest	1.74	1.94	2.10	2.29	2.41
Permian	1.49	1.65	1.84	2.03	2.17
Rocky Mountains	1.33	1.42	1.50	1.57	1.65
San Juan	1.30	1.43	1.57	1.76	1.94
Total: Lower 48	1.55	1.71	1.85	1.97	2.05
CANADA					
Alberta	1.07	1.20	1.31	1.44	1.59
British Columbia	1.11	1.24	1.43	1.60	1.76
Eastern Canada	3.81	2.67	2.51	2.69	2.90
Saskatchewan	1.57	1.85	2.08	2.35	2.57
Total: Canada	1.10	1.23	1.36	1.49	1.65

The growth rate is considerably lower than previous Commission estimates, which have consistently been in the range of 3-4 percent. The sharp decline in the growth is due to two factors: 1) the use of reserve appreciation in the model for the first time, and 2) the change in the owner/producer's discount rates. Figure 4 compares the current forecast with forecasts produced in the previous two reports.

Figure 4
Comparison of Present and Past
California Energy Commission
Lower 48 Wellhead Price Forecasts



Natural Gas Supplies and Prices at the California Border

Four producing regions supply California with natural gas. Three of them, the Southwest U.S., the Rocky Mountains, and Canada provide approximately 85 percent of all gas consumed in the state. The remainder is produced inside California.

Staff expects adequate supplies to be available from each of the four regions providing gas to California during the forecast period. Supplies available to California are expected to increase from 5.9 BCF/D in the 1994 base year to 7.8 BCF/D by 2019. No significant changes are anticipated in the market shares of supplies coming from the Southwest, Canada, the Rocky Mountains, and California producers. Southwest supplies will continue to dominate the market, holding approximately half of the market. Canadian producers will supply another quarter of the market with the remainder split between Rocky Mountain and California suppliers.

The ability of Southwest suppliers to maintain its market share of supplies to California during the next two decades will be helped to some extent by an emerging gas market in the northern part of Baja California. In July 1997, SoCalGas completed construction of a 25 MMCF/D pipeline to deliver gas to the city of Mexicali. Another 275 MMCF/D of capacity is expected to be placed into service in conjunction with the completion of the power plant near Rosarito. As such, supplies to California include up to 157 BCF of gas delivered via California to northern Mexico. Removing those volumes from the analysis reduces Southwest deliveries from 72-105 BCF, beginning in 2004.

Staff expects the average California border price to increase 1.9 percent per year from $1.68 per MCF in 1999 to $2.46 per MCF in the year 2019. Specific estimates of supplies and prices available to California by region appear in Table 15. The Southwest price represents a weighted average of gas entering California at Topock and Blythe. Canadian gas is priced at Malin near the Oregon border. The border price for Rocky Mountain gas is set at Wheeler Ridge, located at the end of the Kern River pipeline.

TABLE 15
CALIFORNIA SUPPLY SOURCES AND BORDER PRICES
BaseCase

Supplier by Producing Region	1994	1999	2004	2009	2014	2019
Production (TCF):						
California	0.311	0.257	0.341	0.343	0.375	0.388
Southwest	1.012	1.006	1.169	1.220	1.259	1.319
Rocky Mountains	0.243	0.255	0.290	0.307	0.331	0.353
Canada	0.590	0.544	0.604	0.705	0.767	0.795
Total Supply Consumed in California	2.156	2.061	2.403	2.574	2.732	2.854
Price (1995$/MCF)						
California	N/A	1.85	2.06	2.28	2.50	2.72
Southwest	N/A	1.69	1.91	2.10	2.32	2.53
Rocky Mountains	N/A	1.76	1.97	2.16	2.37	2.58
Canada	N/A	1.53	1.70	1.85	2.06	2.25
Average Price at California Border	N/A	1.68	1.88	2.05	2.27	2.46

Outlook for Future Pipeline Expansion

One of the more useful features of the NARG model is its ability to indicate areas across the North American gas network that could potentially support pipeline expansion. The model requires in each pipeline corridor a base capacity and a corresponding transportation rate. As the model generates a result, it will increase the capacity needed to meet demand from a particular resource. When this occurs, the calculated utilization rate may exceed 100 percent.

Before assuming that any pipeline corridor in the NARG model with a capacity exceeding 100 percent requires expansion, it is necessary to review how natural gas flows across North America are expected to change over time. Figures 5 and 6 compare gas flows in the 1994 base year and 2019, the last year of the forecast. As the figures indicate, a significant amount of natural gas flows from the Gulf Coast to the midwest and the eastern seaboard. Traditional producing regions in West Texas and Oklahoma, while competing with the Gulf Coast for the same markets, also flow gas west to the Southwest Desert region and California. Producing regions along the Rocky Mountain ridge flow gas both west and east, although pipeline capacity is presently limited and in need of expansion to support future anticipated gas flows.

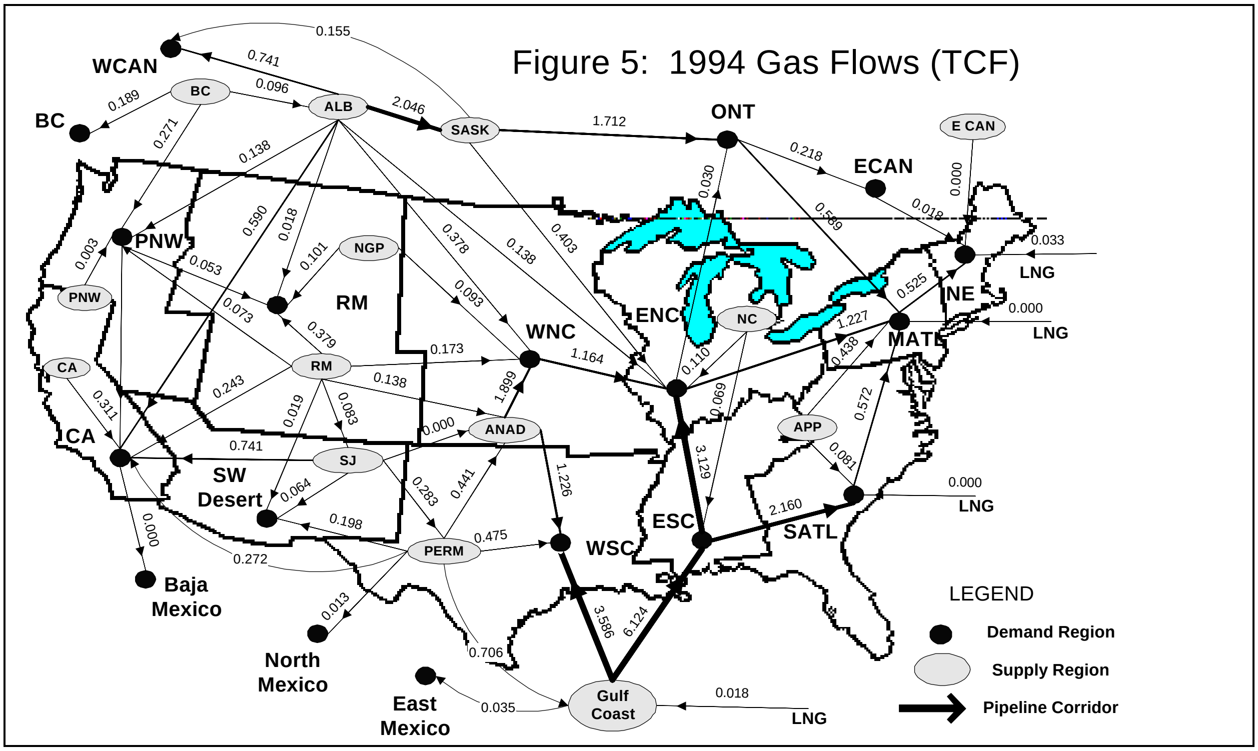


Figure 5: 1994 Gas Flows (TCF)

WCAN
BC
PNW
CA
Baja Mexico
North Mexico
East Mexico
RM
SW Desert
WNC
WSC
ENC
ESC
ONT
ECAN
NE
MATL
SATL
E CAN
NGP
ALB
SASK
RM
SJ
ANAD
PERM
NC
APP
Gulf Coast
LNG
0.155
0.741
0.096
0.189
2.046
1.712
0.271
0.138
0.218
0.000
0.018
0.033
0.000
0.590
0.018
0.101
0.378
0.138
0.403
0.030
0.589
0.525
1.227
0.003
0.053
0.073
0.379
0.093
0.173
1.164
0.110
0.438
0.311
0.243
0.138
0.019
0.083
0.000
1.899
0.069
0.572
0.741
0.064
0.283
0.441
1.226
3.129
0.081
0.000
0.198
0.475
2.160
0.000
0.272
0.013
3.586
6.124
0.706
0.035
0.018
LEGEND
Demand Region
Supply Region
Pipeline Corridor

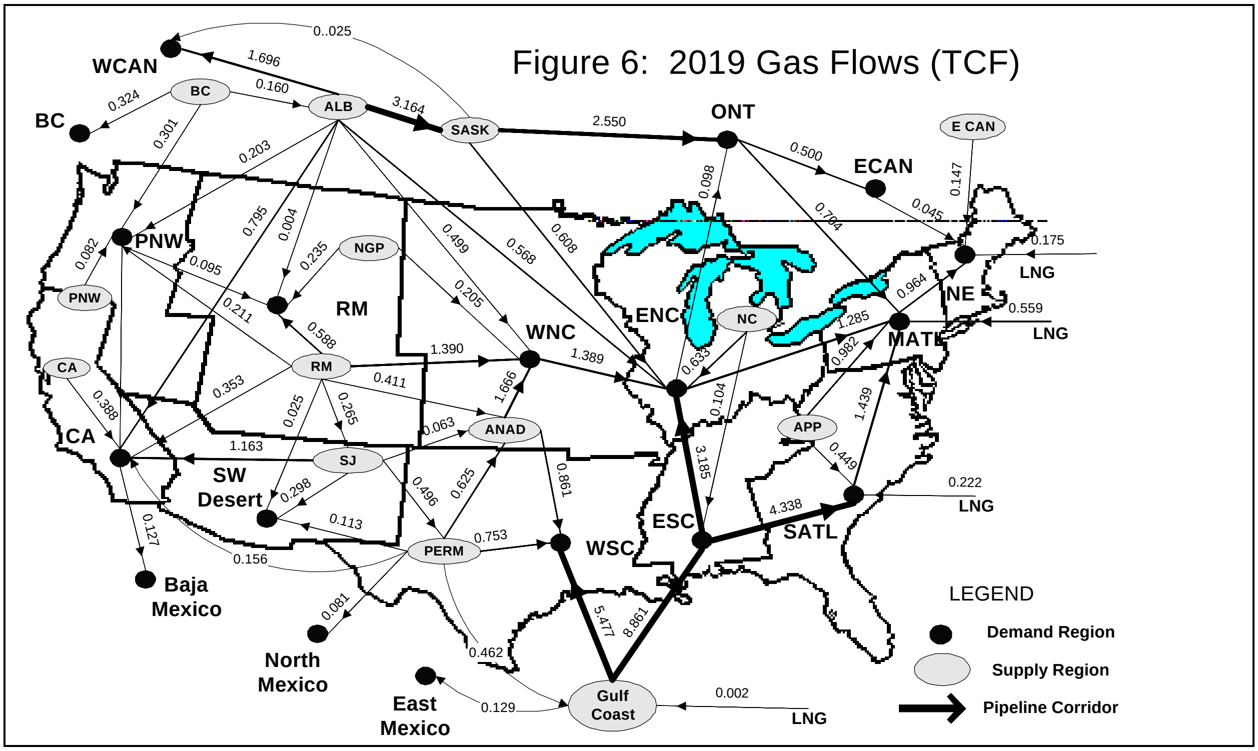


Figure 6: 2019 Gas Flows (TCF)

WCAN
BC
PNW
CA
Baja Mexico
North Mexico
East Mexico
RM
SW Desert
WNC
WSC
ENC
ESC
ONT
ECAN
NE
MATL
SATL
E CAN
NGP
ALB
SASK
RM
SJ
ANAD
PERM
NC
APP
Gulf Coast
LNG
0..025
1.696
0.160
0.324
3.164
2.550
0.301
0.203
0.500
0.147
0.045
0.175
0.559
0.795
0.004
0.235
0.499
0.568
0.608
0.098
0.704
0.964
1.285
0.082
0.095
0.211
0.588
0.205
1.390
1.389
0.633
0.982
0.388
0.353
0.411
0.025
0.265
0.063
1.666
0.104
1.439
1.163
0.298
0.496
0.625
0.861
3.185
0.449
0.222
0.113
0.753
4.338
0.127
0.156
0.081
5.477
8.861
0.462
0.129
0.002
LEGEND
Demand Region
Supply Region
Pipeline Corridor

Canadian gas generally flows from west to east, as the Western Canadian Sedimentary Basin accounts for the vast majority of gas produced. Exports to the Lower 48 are expected to continue during the next 20 years as new pipeline projects come on line and Sable Island productive capacity develops.

The following discussion summarizes pipeline expansion opportunities for selected regions in North America.

- **Rocky Mountains**
  All pipelines linked to other regions could support expansion as early as 1999. Utilization rates for Rocky Mountain pipelines going to the West North Central region exceed base capacity estimates by 53 percent (217 BCF) in 1999, 137 percent (555 BCF) in 2014, and (986 BCF) 244 percent in 2019. Pipelines connecting the Rocky Mountains with the Anadarko region exceed total capacity by 29 percent (69 BCF) in 1999 and 73 percent (174 BCF) in 2019. Kern River capacity, already transporting gas at a level above rated capacity, exceeds base year capacity by 21 percent (45 BCF) in 2004 and 48 percent (120 BCF) in 2019.

- **Gulf Coast**
  Onshore pipelines linked to other regions do not need pipeline expansion until 2014, when an additional 631 BCF is needed. More than 1.2 TCF of new pipeline capacity is required by the end of the forecast period. Given the rapid increase in offshore drilling activity, staff expects significant need for expanded gathering lines and transportation links immediately, continuing throughout the 20-year forecast.

- **Canada**
  Pipeline expansions in Canada are driven by U.S. exports to midwestern and northeastern U.S. markets. Pipeline expansions are needed on TransCanada Pipeline between Alberta and Ontario in 1999 to support needed expansions on the Great Lakes and Northern Border systems. No expansion is necessary on Canadian pipelines for delivering gas to Northwest Pipeline, PGT, Iroquois, or Niagara during the forecast horizon.

Regarding future expansion potential of pipelines delivering gas to the California border, the answer differs depending on which part of the pipeline systems are being reviewed. For example, at the California border, additional capacity will be needed for Kern River and PGT by 2004 and 2009, respectively. Southwest capacity will not need expansion at the California border during the forecast period.

The results presented in Table 16, however, do not reveal the entire pipeline expansion picture to California. Analyzing each system in total reveals that pipeline expansion will actually be needed at some point for each pipeline system delivering gas to the state. On PGT, the portion of the system closest to California will become increasingly constrained over time rather than the portion closest to Canada. The pipeline from Stanfield to Malin will need 77 BCF of capacity in 2009, 139 BCF in 2014, and 168 BCF in 2019. The Kingsgate to Stanfield segment, while reaching full capacity in 2014 only exceeds it slightly; as such, any incremental capacity needed is small enough to accomplish the objective through increased compression.

TABLE 16
PIPELINE UTILIZATION RATES
FOR INTERSTATE PIPELINES TO CALIFORNIA
(Expressed as a Percentage of Base Year Capacity)

Supply Region	CA Border Point	1999	2004	2009	2014	2019
Canada	Malin	86.5	96.2	111.7	121.2	125.6
Southwest	Topock:					
	to PG&E	53.8	53.6	52.6	50.5	52.2
	to SoCalGas	71.7	86.9	94.5	100.4	105.3
	to Mojave	50.7	53.4	54.1	52.7	53.4
	Combined	62.0	69.7	73.1	74.9	78.0
	Ehrenburg/Blythe: to SoCalGas	64.1	79.8	82.5	86.2	91.3
Rocky Mountains	Wheeler Ridge	106.6	120.7	128.5	138.7	148.0

The expansion picture for pipelines delivering San Juan and Permian Basin (El Paso and Transwestern) gas to California is the reverse of PGT. While combined El Paso/Transwestern delivery capacity at the California border will not need any expansion during the forecast period, additional takeaway capacity will be required to move gas from the San Juan Basin. The northern part of the El Paso and Transwestern pipelines will need expansion to both the east and the west. The portion of the system moving San Juan Basin east to midwestern markets will require 32 BCF of incremental capacity in 1999. A maximum of 83 BCF of new capacity will be needed during the forecast. Gas flowing west to California, Southern Nevada, and portions of Arizona and New Mexico will exceed its current capacity level by 2004, requiring expansion of 214 BCF. Nearly 370 BCF of new capacity will be needed by 2019.

Outlook for California Producers

Even though California production holds a locational advantage over gas produced in other regions, in-state gas has lost significant levels of market share during the past 11 years. In 1986, California gas satisfied more than one-quarter of consumer needs. By comparison in 1997, it gained only about 15 percent of the California gas market. The steady decline in market share was largely the combination of increased competition at the wellhead and contractual restrictions between producers and PG&E which precluded producers from gaining access to the spot market. As such, 1997 California production was 41 percent lower than it was in the mid-1980s.

Recent reports from the California Division of Oil & Gas suggest that the bottom of the market may have been reached. The Division reports that 1997 California natural gas production was 291 BCF, about the same level realized in 1995 and 1996. Removing offshore production from the picture, onshore production increased to 242 BCF, a slight increase compared to the previous two years.[18]

Looking beyond the present situation, staff sees new hope for an upward swing in California production during the new few years. In Kern County, the February 1998 sale of the Elk Hills Naval Petroleum Reserve to Occidental Petroleum was finalized, privatizing one of three petroleum reserves previously established for the Navy. Considered the largest producing natural gas field in the state, as much as 200 MMCF/D of additional production previously reinjected to produce crude oil will soon be sold on the open market. The field is strategically located in the heart of Kern County, directly connected to SoCalGas and easily accessible by PG&E.[19]

In Northern California, drilling activity is up for the first time in years. New permits for wells in 1997 were up 25 percent from the previous year. Higher natural gas prices over the past year have sparked a willingness to invest in 3-D seismic surveys throughout the Sacramento region.[20] In one published report, Tri-Valley Oil & Gas recently began drilling north of the town of Tracy in what has been referred as “the biggest hunt for natural gas in 36 years.”[21]

Staff’s outlook for California production during the forecast period is positive after initial drops in 1999. After reaching a low of 257 BCF in 1999, in-state production is expected to increase by 2 percent per year to 388 BCF in 2019. It is important to note that the forecast does not account for the newly available Elk Hills supply, as the sale was completed after the numerical analysis of this report was completed. Even without including the sale of Elk Hills in the analysis, the forecast does consider Northern California activity as noted above, predicting that Northern California production will rebound from its continuing decline as these new developments become operational. After falling to 61 BCF in 1999, Northern California production will increase steadily, reaching 142 BCF by the end of the forecast.

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[18] California Department of Conservation. *1997 Preliminary Report of California Oil and Gas Production Statistics* , Publication PR03, January 1998.

[19] “With OXY at the Helm, Elk Hills Expected to Flow More Gas,” *Natural Gas Intelligence*, February 23, 1998, p.8.

[20] Peyton, Carrie. “Geologists Blast for Gas,” *The Sacramento Bee*, November 17, 1997, p.1.

[21] Stannard, Matthew B. “Investors Tapping into Tracy, Hoping to Find Natural Gas,” *Argus*, December 24, 1997.

III. CALIFORNIA END-USE GAS PRICE FORECAST

This section provides staff's end-use price forecast by customer sector in the PG&E, SoCalGas, and SDG&E service territories. Different from other parts of the analysis, the end-use forecast was performed independent of the NARG model, although the NARG model-generated California border price was used as a starting point. Staff allocated interstate transportation costs to core (residential, commercial, and small industrial) and noncore (large industrial, EOR, and electric generation) customers, derived an adjusted California border price for each group, and added intrastate charges to obtain the end-use price. A discussion of the methodologies and assumptions used for developing this forecast follows a brief overview of the pipeline network delivering gas to the state.

General Overview of the California Natural Gas Network

Four interstate pipelines deliver natural gas to California (Table 17). Canadian supplies enter California at Malin, Oregon via the PGT system. The gas flows into PG&E Lines 400 and 401, the utility's main long-distance or backbone transmission lines from the north. Line 400 has a capacity of 1,020 MMCF/D and is principally assigned to meet PG&E's core demand. Line 401, the California portion of the PGT/PG&E Expansion completed in 1993, has a rated capacity of 813 MMCF/D and is available to all shippers throughout the state.

TABLE 17
INTERSTATE PIPELINE CAPACITY AND UTILITY TAKEAWAY CAPACITY
(MMCF/D)

Interstate Pipelines and Delivery Capacity to California		Takeaway Capacity at California Border		
Pipeline	Delivery Capacity	Mojave	PG&E	SoCalGas
PGT	1,800		1,855	
El Paso	3,530	400	1,140	1,990
Transwestern	1,065			750
Kern River	700			
Wheeler Ridge Receipt Point				600
Total	7,095	400	2,995	3,340

Notes:

- PGT delivery capacity to California is impacted by how much gas flows into the Tuscarora system. Tuscarora can take 112 MMCF/D from PGT at Malin, reducing California deliveries by up to the same amount.
- PG&E may receive up to 1,140 MMCF/D from a combination of El Paso, Transwestern, Kern River and Mojave deliveries.
- Mojave receives its supply from El Paso and Transwestern.
- Wheeler Ridge receives gas from Kern River, Mojave and PG&E.
- Not listed, but direct deliveries are made by Kern River, Mojave, and from California production to industrial, electricity generation and EOR facilities.

Southwest supplies from the San Juan, Permian and Anadarko Basins are delivered to the PG&E, SoCalGas, and Mojave systems at Topock, Needles, and Ehrenburg along the Arizona-California border. The northern part of the El Paso system delivers San Juan gas to California at Topock and Ehrenburg, moving gas to the south along the Havasu Crossover. Permian gas moving on El Paso's southern system goes to Ehrenburg only. Approximately 750 MMCF/D of gas flowing through the Transwestern system moves into the SoCalGas system at Needles. Since the 1992 expansion of the Transwestern system, another 315 MMCF/D of gas can also flow through Topock. No additional intrastate capacity was added to accommodate the expanded Transwestern capacity.

Rocky Mountain supplies enter the state via the Kern River system. Approximately 700 MMCF/D of capacity is available to California with the "effective California border" point located at Wheeler Ridge in the lower San Joaquin Valley. The Wheeler Ridge receipt point can take gas not only from Kern River but also from Mojave and PG&E systems for delivery into the SoCalGas service area. Flow through capacity at Wheeler Ridge equals 600 MMCF/D. Additional supplies on Kern River and Mojave can also be delivered to a number of EOR producers and electric generators located in Kern and San Bernardino counties.

Assumptions Surrounding Calculation of California Border Prices

The price of natural gas delivered at the California border is the sum of three specific components: 1) wellhead or commodity price, 2) interstate transportation rate, and 3) fuel cost associated with compression and line losses. In this analysis, natural gas entering the state using firm transportation was assessed the maximum interstate pipeline transportation rate, while nonfirm supply was charged a discounted transportation rate.[22] The analysis assumed the same commodity price regardless of the transportation option selected. Fuel costs were included in the commodity price.

Table 18 presents staff's general assumptions for allocating supply to the various end-use sectors. In Northern California, core customers rely principally on a portion of California production, firm Canadian production, and a small amount of firm Southwest supply. At times when these sources are not adequate, additional supply is drawn from Rocky Mountain and nonfirm Canadian sources.

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[22] For PGT and Kern River, there is very little pipeline capacity available for discounting. Shippers transporting gas on these systems almost always pay the maximum transportation rate. With the effective price at the California border based on the price at Topock, some form of discounting often occurs on PGT and Kern River. Rather than appearing directly in the form of a reduced transportation rate, the discount is instead absorbed by either the marketer using its firm capacity or the producers supplying customers with the gas. Staff's analysis assumes that the transportation component is discounted.

TABLE 18
SUPPLY ALLOCATION TO CUSTOMER CLASSES IN CALIFORNIA

	PG&E			SoCalGas			SDG&E
Supply Source	Core	Noncore	EG	Core	Noncore	EG	All
California Production	x	x	x	x	x	x	x
Southwest	x	x	x	x	x	x	x
Canada (Line 400)	x	x	x				
Canada (Line 401)	a	x	x	a	x	x	x
Rocky Mountains	a	x	x	a	x	x	x

Notes:

- The basis for Core and Electricity Generation (EG) supply allocations are the various firm transportation commitments the utilities have with producers and interstate pipeline companies. The remaining supply is allocated to the noncore supply pool.
- "a" denotes that when the normal supply sources are not adequate to meet demand, this source may be used to meet the shortfall.

In the SoCalGas service area, core customers rely on firm supply from California onshore and offshore production as well as the Southwest.[23] Additional supply is made available from nonfirm Canadian sources and the Rocky Mountains when needed. Noncore customers have access to all supply sources, except firm supply delivered on PG&E's Line 400. In the SDG&E service area, supplies are purchased with no specific supply designated to a specific customer or customer sector.

Table 19 presents the firm capacity assumptions used in the analysis for each of the Northern California supply sources. Firm supplies from California production and Canada were based on PG&E's Gas Accord, a settlement agreement implemented on March 1, 1998.[24] The Accord allocates 50 MMCF/D in firm capacity from California production to core customers. Based on historical information from a variety of sources,[25] staff assumed an additional 55 MMCF/D of capacity to be available for non-utility pipelines. Remaining California production was allocated to noncore customers using the PG&E system.

From Canada, 600 MMCF/D of firm Canadian capacity was reserved for core customers in Northern California, based on the terms of the Gas Accord settlement. From the Southwest, 100 MMCF/D of firm transportation capacity was reserved for the core and 50 MMCF/D of firm transportation capacity for electric generation customers on Transwestern. Staff assumed these capacity holdings remain in place throughout the forecast.

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[23] SoCalGas also has a firm contract for 240 MMCF/D of Canadian supply. This supply is delivered by displacement through the San Juan Basin and is accounted for under Southwest supply.

[24] The ***Gas Accord*** is a settlement agreement between PG&E and many of its customers and suppliers to resolve several rate cases before the CPUC and provide movement towards unbundling PG&E services. The ***Gas Accord*** was approved by the CPUC in Decision 97-08-055 on August 1, 1997.

[25] Sources include the ***California Gas Report***, the California Division of Oil, Gas and Geothermal Resources ***Annual Report,*** and the California Energy Commission's Quarterly Fuels and Energy Report filings.

TABLE 19
NORTHERN CALIFORNIA
FIRM CAPACITY ASSUMPTIONS (MMCF/D)

Supply Source	Present to 1997	1998 - 2008	2009 - 2017
California Production to PG&E	50	50	50
Southwest Capacity			
Core	586	100	100
Electricity Generation	50	50	50
Canadian Capacity	586	600	600

Notes:

- Firm transportation costs are priced at the maximum rate of $0.514 per MCF (1995$) for Canadian supply transported from the Canadian wellhead to Malin and $0.342 per MCF for Southwest gas transported to the California border at Topock, Needles, or Ehrenburg.

Firm capacity assumptions for Southern California are provided in Table 20. Capacity reservations assumed for California sources were based on the recorded 1996 statewide sources and disposition summary found in the ***1997 California Gas Report***. Of the total California supply entering the SoCalGas system, 31 percent was assumed to be allocated to the core market with the remaining 69 percent (transport and exchange) allocated to the noncore pool.

TABLE 20
SOUTHERN CALIFORNIA
FIRM CAPACITY ASSUMPTIONS (MMCF/D)

Supply Source	Present to 1998	1999 - 2006	2007 -2017
California Production to SoCalGas	31%	31%	31%
Southwest Capacity			
SoCalGas	1,044	1,044	745
SCE	130	0	0
SDG&E	10	10	10
Canadian Capacity			
SoCalGas	0	0	0
SCE	200	0	0
SDG&E	50	50	50

Source: SoCalGas Application A.96-03-031 and Decision 97-04-082.
Discussions with SoCalGas, SCE, and SDG&E representatives.

Notes:

- California Production to SoCalGas equals onshore and offshore production less direct deliveries to industrial and EOR operations.
- SoCalGas maintains sufficient firm Southwest pipeline capacity and California production to meet core demand.
- SCE negotiated out of its Canadian and Southwest firm capacity contracts. Its contract with PGT ended at the end of 1997 while its contract with El Paso ends after 1998.
- Firm Southwest transport rates are $0.342 per MCF (1995$).
- Staff assumes SDG&E's Canadian transport includes discounted rates.

Southwest capacity was reserved on the El Paso and Transwestern systems. The 1,044 MMCF/D of firm SoCalGas capacity reserved for the core through 2006 represents the quantity of firm capacity allocated to meet core demand. Beyond 2006, upon the termination of SoCalGas' firm contracts with El Paso and Transwestern, staff assumed the utility retains 745 MMCF/D of firm capacity which, coupled with supply from California production, is needed to meet core requirements for the remaining years of the forecast.

SCE is in the process of selling its natural gas fired electricity generation facilities and will no longer need firm interstate pipeline capacity once the sale of the plants is completed. SCE has already reduced its firm capacity reservation on the PGT lines from 200 MMCF/D to zero. Staff assumed SCE will buy out of its 130 MMCF/D firm capacity contract with El Paso by the end of this year.

After lengthy discussions with SDG&E, staff assumed that the utility's firm capacity contracts for Southwest and Canadian supply will continue throughout the forecast. This conclusion was reached before SDG&E announced it was going to sell some or all of its generation facilities. It is not certain what impact the impending sale will have on the utility's firm capacity contracts, as SDG&E does not designate specific supplies to discrete demand sectors.

Calculating Specific California Border Prices

While the NARG model generates an aggregated California border price, staff computes a separate border price for core, noncore, and electric generation customers. Border prices for each group differ based on the supply and capacity assumptions discussed in the previous section. The main factor driving the difference is the transportation rate that the NARG model computes for each pipeline segment delivering gas to California. This section describes how commodity costs and interstate transportation costs are calculated for the various customer sectors.

Base interstate transportation rates are used in the NARG model for each pipeline segment in the model. Transportation rates move above or below the base rate in the NARG model, depending on the level of pipeline capacity being utilized. The capacity utilization factors and corresponding multipliers were previously discussed in Section II of this report (see Table 11). For example, a pipeline with a 70 percent capacity utilization rate generates a transportation rate multiplier of 0.725. In other words, a pipeline segment flowing at 70 percent of capacity has a NARG model transport rate equal to 0.725 times the base rate. Pipeline capacity factors for individual pipeline corridors are found in Appendix F.

Forecasted transportation rates from Canada, the Rocky Mountains, and the Southwest supply regions to California were derived by summing the NARG model-generated pipeline transportation rate for each segment of each link between the wellhead and the California border. For Alberta, gas delivered to California uses three interstate transport segments. The first includes the NOVA Corporation and Alberta Natural Gas systems, delivering the gas from the wellhead to the international border near Kingsgate, British Columbia. The second segment proceeds from Kingsgate to Stanfield, the first 277 miles of the PGT system. The final segment moves the gas another 335 miles to the California-Oregon border at Malin.

As Table 21 illustrates, the projected transportation rate to move gas from Alberta to the California border in the year 2000 is $0.394 per MCF, 23 percent below the non-discounted rate of $0.514 per MCF. Note that the 23 percent discount is not uniform across all three segments, as a 39 percent discount is applied to the segment delivering gas to the international border.

TABLE 21
ALBERTA TRANSPORT COST AT MALIN FOR THE YEAR 2000

Pipeline Segment	Capacity BCF	NARG Flow-BCF	Capacity Factor	Discount Factor	Non-Discounted Rate 95$/MCF	Actual NARG Rate 95$/MCF
Wellhead to Kingsgate	1190	728	.612	.612	0.258	$0.158
Kingsgate to Stanfield	909	693	.762	.824	0.116	$0.096
Stanfield to Malin	657	581	.884	1.000	0.140	$0.140
Total Transportation Cost					$0.514	$0.394

Both parts of the PGT segment carry higher utilization rates than the segment north of the border; thus, the discount factors are lower, 18 percent on the PGT link from Kingsgate to Stanfield and zero on the link between Stanfield and the California border at Malin.

The commodity component of the California border price was determined for each year by subtracting the actual NARG model transport cost from the NARG model-generated California border price. Using Alberta for the year 2000 again as an example, subtracting the actual NARG model transport cost of $0.394 per MCF to Malin from the NARG model-generated delivered price of $1.564 per MCF yields a commodity price of $1.170 per MCF. The commodity price from each supply region is the same for the core, noncore and electricity generation end-use sectors. The total weighted average commodity cost for each utility service area may differ, however, due to the mix of supplies coming to California. Transportation costs for each customer sector also are different.

The NARG model-generated transport rate represents a weighted average of firm and non-firm transport charges. While the firm transport rates are equal to the maximum rate shown above, non-firm rates are estimated, as illustrated in Table 22 for Alberta supply to California. Multiplying the NARG model-generated throughput at Malin by the NARG-generated aggregate transport rate produces a total transport revenue of $228.9 million. Firm capacity holders pay $121.8 million of the total, equal to the total firm throughput (237 BCF) times the $0.514 per MCF. Subtracting the firm transport revenue from the total leaves $107.1 million for non-firm shippers to pay. Dividing that amount into the non-firm supply of 344 BCF produces a discounted non-firm transport rate to deliver Alberta supply to California of $0.311 per MCF.

TABLE 22
ESTIMATED NON-FIRM TRANSPORTATION COST
TO DELIVER ALBERTA GAS TO CALIFORNIA IN THE YEAR 2000
1995 Dollars

Sector	Quantity (BCF)	Rate (95$/MCF)	Revenue (MM$)
Total Supply to Malin	581	$0.394	$228.9
Firm Supply	237	$0.514	$121.8
Nonfirm Supply	344	$0.311	$107.1

Note: Firm supply includes firm PG&E core and SDG&E capacity.

Depending on known contractual arrangements, natural gas supply from each supply source was assigned to one of three supply pools. Firm supply to meet core requirements was classified as a core supply. Likewise, firm supply used to meet electricity generation was categorized with the electricity generation supply pool. The remaining supply from each source was placed in the noncore supply pool. Each supply assigned to a particular supply pool had associated with it the corresponding commodity and interstate transportation charge.

The noncore supply pool was used not only to meet the noncore needs but also supply shortfalls for the core and electricity generation sectors. The supply for each supply pool was aggregated and yearly weighted average commodity and transportation costs were determined. A summary of these weighted average prices for core, noncore and electricity generation are provided for selected years in Tables 23 and 24. The differences in commodity and transport costs can be attributed to the different supply mix for each supply pool.

TABLE 23
CALIFORNIA BORDER PRICES - NORTHERN CALIFORNIA
(1995$/MCF)

Sector	Item	1997	2000	2005	2010	2017
Core	Commodity	$1.718	$1.274	$1.416	$1.563	$1.790
	Interstate Transport	0.460	0.469	0.464	0.462	0.468
	Total	$2.178	$1.743	$1.880	$2.025	$2.258
Noncore	Commodity	$1.788	$1.288	$1.429	$1.596	$1.826
	Interstate Transport	0.204	0.272	0.347	0.373	0.465
	Total	$1.992	$1.560	$1.776	$1.969	$2.291
Electric Generation	Commodity	$1.821	$1.334	$1.441	$1.605	$1.837
	Interstate Transport	0.217	0.286	0.347	0.371	0.457
	Total	$2.038	$1.620	$1.788	$1.976	$2.294

Notes:

- 1997 values are estimated.
- Interstate transportation fuel is included in the commodity price.
- Totals may not sum due to rounding.

TABLE 24
CALIFORNIA BORDER PRICES - SOUTHERN CALIFORNIA
(1995 $/MCF)

Sector	Item	1997	2000	2005	2010	2017
SoCalGas - Core	Commodity	$2.152	$1.489	$1.680	$1.859	$2.157
	Interstate Transport	0.546	0.370	0.346	0.341	0.362
	Total	$2.697	$1.859	$2.026	$2.200	$2.519
SoCalGas - Noncore	Commodity	$1.814	$1.482	$1.697	$1.853	$2.138
	Interstate Transport	0.202	0.214	0.337	0.401	0.455
	Total	$2.015	$1.696	$2.034	$2.254	$2.593
SoCalGas - Electric Generation	Commodity	$2.086	$1.520	$1.697	$1.853	$2.138
	Interstate Transport	0.246	0.234	0.337	0.401	0.455
	Total	$2.331	$1.754	$2.034	$2.254	$2.593
SDG&E	Commodity	$2.086	$1.461	$1.644	$1.804	$2.088
	Interstate Transport	0.246	0.303	0.371	0.422	0.474
	Total	$2.331	$1.765	$2.015	$2.225	$2.563

Notes:

- 1997 values are estimated.
- Interstate transportation fuel is included in the commodity price.
- SDG&E commodity and interstate transport costs are at the California border.
- SDG&E commodity and interstate transport costs are uniformly distributed to all customers.
- Totals may not sum due to rounding.

Intrastate Price Assumptions

Gas utility in-state transmission charges comprise the final component of the end-use price. It consists of five components: utility base margin, backbone transmission charges for PG&E customers, interstate transition cost surcharges (ITCS), PITCO/POPCO costs for SoCalGas customers, and other regulatory charges. These revenue requirements and cost allocations are established by the CPUC through general rate cases, BCAP, and PBR proceedings. This forecast reflects CPUC decisions, utility advice letters and other filings available through November 1997.

Utility Margin Requirement

Margin requirement refers to the revenues needed by the utility to cover system administration costs and the operation costs of transmission, distribution and storage functions. Historically, these revenues were determined on a triennial basis in a General Rate Case. Recently, a PBR approach has become more widely used, where a base revenue requirement is initially determined and adjusted annually based on operational efficiency, load growth, and inflation, among other factors. Each customer class is allocated a portion of the utility margin using some combination of fixed and variable rates.

Staff’s forecast of PG&E’s margin requirement was based on actual 1995 and 1996 margins provided by the utility. The actual data were adjusted to reflect PG&E’s recovery of its full authorized rate of return and then averaged to obtain a 1996 revenue requirement of $1,565 million (1995 dollars). Based on the ***1995 Natural Gas Market Outlook*** forecast, annual escalation rates were calculated and applied to the 1996 revenue requirement for each forecast year.

Staff then removed from the utility-provided margin estimate the operational costs associated with PG&E's backbone system (Line 300, 400, 401, and gathering). Removing the backbone costs from the margin is consistent with the Gas Accord settlement which unbundled these costs from the margin and established a process for recovering the costs volumetrically. Staff removed a backbone revenue requirement of $201.5 million ($193.9 million in 1995 dollars) from the 1997 utility-provided margin requirement.[26]

Testimony submitted by PG&E in its BCAP proceeding was used as the basis for determining how much margin to allocate to each customer class. Table 25 summarizes the components that were used. Not surprisingly, approximately 90 percent of the utility's total margin requirement is allocated to core (residential and small commercial) customers. Most of those costs are included as distribution-related costs.

TABLE 25
SUMMARY OF PG&E MARGIN REQUIREMENTS FOR 1998
MILLIONS OF 1998 DOLLARS

Sector	Yearly Throughput MDth	Margin Distr	Access Charge	Core Backbone	Local Transm	Storage	Total
Residential	217.1	562.5	0.0	25.3	57.2	26.3	671.3
Small Commercial	69.1	146.3	32.7	8.0	18.2	8.4	213.6
Large Commercial	5.7	3.9	0.2	0.5	1.5	0.5	6.6
Distribution	35.7	23.2	4.2	0.0	4.8	0.0	32.2
Transmission	161.9	0.0	4.9	0.0	21.8	0.0	26.7
Cogen	88.6	1.2	0.7	0.0	11.9	0.0	13.7
Electric Generation	180.7	0.0	1.3	0.0	24.3	0.0	25.7
Coalinga	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Palo Alto	3.6	0.0	0.0	0.0	0.5	0.0	0.5
Total	762.8	737.1	44.2	33.8	140.3	35.3	990.6

Source:

- Source: PG&E, Revised BCAP Prepared Testimony and Workpapers, Aug. 27, 1997 (A. 97-03-002).
- In the allocation, Mather Field and Energy Island were included in small commercial. Coalinga and Palo Alto were equally allocated to residential and small commercial.

Staff's margin requirement forecast for SoCalGas was based on the indexing formula adopted by the CPUC in the utility's PBR proceeding.[27] The actual formula adopted by the CPUC is slightly different than the one used in this analysis since it places greater emphasis on customer-specific margins. Staff's formula, which is shown below, calculates the margin for all utility customers:

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[26] See the ***Gas Accord, PG&E Workpapers for the Gas Accord Settlement Agreement***, August 20, 1996, Chapter 18.

[27] CPUC Decision No. 97-07-054, p. 33.

Margin (Year 1) = Margin (Year 0) * (1 + Inflation - Productivity + Growth in Throughput)

After assuming a 1997 margin of $1315.4 million (nominal),[28] forecast year margins were computed using Energy Commission inflation factors and expected growth levels in throughput. Productivity factors for the first five years were obtained from the PBR decision.[29] After the fifth year, the productivity factors were assumed to decline at 0.1 percent per year, reaching a low of 1.5 percent and held constant thereafter.

Margin allocation factors for SoCalGas were estimated using recent advice letter filings and CPUC decisions.[30] Staff classified the utility's G-10 tariff rate as core commercial and G-20 tariff rate as core industrial. G-30 was split into noncore commercial and industrial using historical values from the ***1996 California Gas Report***. A margin allocation was also included to cover SDG&E's transport cost to move natural gas through the SoCalGas system.

For SDG&E, margin forecasts through 2010 were provided to staff by the utility based on the CPUC April 1997 combined BCAP decision for SoCalGas and SDG&E. The forecast was converted from nominal to 1995 dollars. Projections between 2010 and 2017 were estimated in the same manner used to estimate PG&E's margin requirement in the later years of the forecast.

The April 1997 BCAP decision was also used to determine SDG&E's margin allocation factors. In applying the factors, SDG&E's large commercial sector was assumed to be core industrial. Noncore commercial/industrial was equally divided between noncore commercial and industrial sectors.

Margin forecasts and allocation factors for each of the three utilities can be found in Appendix G.

PG&E Backbone Transmission Rates

Backbone transmission rates were only estimated for the PG&E service area since they are not yet unbundled from SoCalGas and SDG&E rates. As mentioned earlier, the PG&E backbone transportation rate includes the costs of PG&E Lines 300, 400, 401, and gathering costs. The rates used in this analysis were based on a recent PG&E Advice letter filed in December 1997.[31]

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[28] SoCalGas Advice No. 2609, dated July 23, 1997.

[29] CPUC Decision No. 97-07-054, p. 38.

[30] Unit margin costs were obtained from SoCalGas Advice Letter 2640, filed on July 23, 1997. EOR revenue was from SoCalGas Advice Letter 2609, and system throughput was obtained from CPUC Decision 97-04-082. G-30 was split between noncore commercial and industrial using ***California Gas Report*** historical values.

[31] See PG&E Advice Letter 2052-G, dated December 1, 1997.

Transportation rates for Line 300 and Line 400 were held constant throughout the forecast at $0.147 per MCF and $0.109 per MCF, respectively.

Line 401's rate was allowed to steadily decrease from the initial 1997 rate of $0.368 per MCF (documented in the Gas Accord) to a value that would effectively equate costs for the rolled-in Line 400/401 with Line 300 in 2010. From that point onward, the rate was held constant at $0.147 per MCF. Table 26 compares the backbone rates during selected years for Lines 300, 400, 401, and the rolled-in rates for Line 400/401.

TABLE 26
PG&E BACKBONE RATES FOR SELECTED YEARS
1995 DOLLARS PER MCF

Pipeline Segment	1997	2000	2005	2010	2017
Line 300	$0.147	$0.147	$0.147	$0.147	$0.147
Line 400	$0.109	$0.109	$0.109	$0.109	$0.109
Line 401 (Incremental)	0.368	0.309	0.223	0.138	0.138
Phased Line 400/401	$0.227	$0.231	$0.196	$0.147	$0.147

Source: PG&E Advice Letter 2052-G, December 1, 1997.

The approach for rolling-in the costs of PG&E Lines 400 and 401 in this analysis was defined in the Gas Accord. The Gas Accord initially rolls-in 200 MMCF/D of Line 401 capacity in 1997, increasing to 375 MMCF/D in 2002, the last year of the Gas Accord. Beyond 2002, staff assumed that an additional 25 MMCF/D of Line 401 costs will be rolled-in each year, continuing until the rolled-in Line 400/401 rate equals the Line 300 rate. Table 27 provides the phase-in capacity for Lines 400 and 401. The transportation rate for the rolled-in line shown in the previous table was ultimately determined by weighting corresponding volumes and rates.

Based on the Gas Accord workpapers, staff assumed a constant $0.10 per MCF charge for northern California gathering charges.

TABLE 27
LINE 400 AND LINE 401 ROLLED-IN CAPACITY
MMCF/D

Pipeline Capacity for Roll-In	1997	2000	2005	2010	2017
Line 400	385	385	385	385	385
Line 401 (Incremental)	200	325	450	575	750
Rolled-in Line 400/401	585	710	835	960	1135

Source: PG&E Gas Accord Settlement Workpapers, August 20, 1996, Page 18-1.

Utility Surcharges and Other Regulatory Charges

Surcharges are used in natural gas ratemaking to recover costs not considered part of a utility's cost of service but instead are additional charges stemming from some regulatory action. The Interstate Transition Cost Surcharge (ITCS) allows the utilities to recoup the costs of excess firm interstate pipeline capacity the utilities strand or sell to third-party shippers at a price well below the full transport rate.

The issue of PG&E, SoCalGas, and SDG&E holding excess firm interstate pipeline capacity was the direct result of a 1991 CPUC decision prohibiting the utilities from purchasing gas for noncore customers and increased utility bypass stemming from the startup of the Kern River and Mojave pipelines in 1992. By the end of 1992, a significant portion of the firm capacity the utilities had under contract was no longer needed, but the utilities were still responsible for paying for the firm capacity reserved on behalf of the noncore customers.

A process was eventually established by the CPUC to allow the utilities to reduce the shortfall between firm capacity holdings and undercollected capacity revenue. Since 1993, firm interstate capacity not used by the utilities can be posted on the electronic bulletin board of the respective interstate pipeline company, bid for by third-party shippers, and awarded at the maximum or discounted transmission rate. Capacity awarded to other parties at the maximum tariff do not produce any ITCS charge. Quite often, however, capacity is awarded at a discounted rate. The difference between the discount and the full tariff is subject to ITCS consideration.

Staff calculated the ITCS for each utility in three steps. The first step required a determination of how much firm interstate pipeline capacity held under long-term contract was released or stranded by the utility. For PG&E and SoCalGas, each is required to reserve a certain portion of its total interstate capacity holdings to satisfy core customer requirements. Everything above that total is made available to third-party shippers or otherwise stranded.

Step two involved determining the annual ITCS liability. The total dollar liability for stranded capacity applicable to the ITCS was derived by multiplying the full interstate pipeline tariff rate by the amount of capacity stranded, adjusted downward to account for utility revenues generated from releasing capacity. The dollar amount of revenues lost to capacity release is equal to the amount of capacity brokered times the average discounted interstate pipeline tariff. The discounts were based on pipeline flows generated by the NARG model.

The final step required determining the per unit ITCS charge and allocating the total to core and noncore customers. ITCS liabilities were allocated to all customers on an equal cents per therm basis, subject to a 10 percent limit to core customers per CPUC rules.

Staff projects that SoCalGas and SDG&E will incur a combined $38 million in ITCS charges in 1998 with a steady decline through 2006. Annual charges will remain above $20 million through 2002. ITCS rates begin at $0.138 per MCF in 1998, dropping to the 1-2 cent range beginning in 2001. For PG&E, the termination of the El Paso firm capacity contract combined with the full utilization of the PGT line mitigates any future incremental ITCS liability. Remaining ITCS liability will be fully amortized by the end of 1999.

The second surcharge is the result of a global settlement SoCalGas reached with several long-term shippers on several issues related to interstate transportation costs. Included in the settlement is a renegotiation of two gas procurement contracts the utility had with Pacific

Interstate Transmission Company (PITCO) and Pacific Offshore Pipeline Company (POPCO). SoCalGas customers are required to pay a PITCO/POPCO surcharge through the middle of 1999. SDG&E already paid off its share of the settlement costs. Unit costs were estimated based on remaining revenues and staff estimated throughput.

Other Regulatory Accounts is a new feature included in this price forecast. These principally include customer class charges, balancing accounts, and social, environmental and similar programs. After some short-term adjustments, costs under this category were held constant for the entire study period. This account for PG&E is much higher in the near-term compared to the other utilities, due to a high undercollection of natural gas purchases resulting from overestimating demand. Staff assumed this undercollected revenue would be fully balanced during the next five years. Consistent with the other utilities, charges were held constant after the undercollection was balanced.

End-Use Price Summaries

The final step in the process of forecasting natural gas price by customer class is to sum up the various forecasted pricing components described above. Table 28 summarizes the end-use price forecast for each utility by customer sector for 2000, 2005, 2010, and 2017. Actual 1995 and estimated 1997 data are also provided for comparison.

The basecase price forecast provides the most likely trajectory for the natural gas price forecasts to follow. Shifts in supply availability, demand fluctuations, and regulatory changes could cause the prices to move to positions above or below the basecase. Employing the sensitivities discussed in Section VI, an upper and lower pricing bound was prepared. The conditions that were assumed to provide these bounds are not considered to be supportable for the long term, but they do indicate how far prices may stray from the basecase in the short term.

Although prices rose significantly between 1994 and 1997, the current forecast indicates that all market sector prices will drop substantially during the next few years. Thereafter, prices gently tend to increase in real terms, due to a gradual increase in commodity prices. This increase, however, will be partially offset by cross-subsidy reductions and lower costs to operate utility systems.

Natural gas commodity prices throughout North America rose to high levels as a result of increased natural gas demand during the winter of 1996-97, and remained high during most of 1997. Additionally, while natural gas production capability was more than adequate to meet demand, the ability to get production into the pipeline in major supply regions was restricted by the capacity to gather and process the gas for delivery into the pipeline. This condition resulted in less supply competing for market share, and therefore, sustaining higher prices during the past year.

TABLE 28
CALIFORNIA BASECASE END-USE PRICE FORECAST BY SECTOR AND UTILITY
1995 DOLLARS PER MCF

Utility	Core			Noncore					System
and Year	Resid	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	Avg.
PG&E									
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1997	7.13	7.12	4.69	3.45	2.80	2.58	2.66	2.66	4.27
2000	6.09	6.08	3.42	3.01	2.05	1.98	1.99	1.99	3.36
2005	5.67	5.67	3.44	3.10	2.21	2.17	2.16	2.16	3.31
2010	5.59	5.59	3.49	3.21	2.37	2.34	2.31	2.31	3.33
2017	5.57	5.58	3.63	3.46	2.68	2.64	2.62	2.62	3.52
SoCalGas									
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1997	6.93	5.19	4.26	3.07	3.06	2.85	2.87	2.87	4.42
2000	5.91	4.20	3.28	2.27	2.26	2.28	1.99	1.99	3.44
2005	5.84	4.22	3.37	2.51	2.51	2.53	2.24	2.24	3.53
2010	5.78	4.26	3.46	2.70	2.69	2.73	2.44	2.44	3.59
2017	5.86	4.45	3.71	3.02	3.01	3.04	2.77	2.77	3.78
SDG&E									
1995	6.44	6.32	5.31	2.71	2.74	n/a	2.18	2.18	4.01
1997	6.88	6.18	4.72	3.32	3.32	n/a	3.07	3.07	4.56
2000	6.24	5.55	4.11	2.60	2.60	n/a	2.39	2.39	3.89
2005	6.15	5.51	4.18	2.80	2.80	n/a	2.59	2.59	3.78
2010	5.98	5.38	4.18	2.94	2.94	n/a	2.74	2.74	3.76
2017	5.92	5.37	4.31	3.21	3.21	n/a	3.03	3.03	3.90

Notes:
- 1995 prices are historical values.
- 1997 prices are based on partial 1997 supply and price data.
- 2000 and subsequent year prices are forecasted.
- Adopted March 18, 1998 by the California Energy Commission for the ***Fuels Report***.

Since November 1997, natural gas prices have fallen, primarily due to weather conditions being warmer than normal. In fact, the effects of El Niño has reduced winter heating demand for natural gas in most regions of the Lower 48, placing downward pressure on natural gas prices. December 1997 commodity costs actually dropped to $2.25 per MMBtu, compared to the November 1997 price of $3.25 per MMBtu. With a continuation of warmer than normal winter conditions, January 1998 commodity prices fell an additional 10 to 20 cents per MMBtu. Lower natural gas price trends should continue after the winter season due to a decreased amount of gas that will be needed to refill storage facilities for the next winter. Further, new supplies from offshore Gulf production region are expected to become available later this year. With lower demand to fill storage and more supply available, competition to sell gas could drive prices even lower.

After prices bottom out by the turn of the century, natural gas prices are expected to rise in real terms. Commodity costs will show small annual increases of about three cents per MCF. New technologies to explore, find, develop, and produce natural gas will help to keep the commodity prices from rising at a higher rate. Current CPUC policies to reduce end-use price subsidies and provide for more efficient utility operations will partially offset commodity increases.

Detailed annual end-use price estimates for each utility through the year 2017 are presented in Appendices H, I, and J. Each service area for the base, low, and high cases contain five tables. The first table in the series summarizes the total delivered price for residential, commercial, industrial, TEOR, cogeneration and electricity generation facilities. The next three tables furnish the forecasted pricing components for the core, noncore and electricity generation sectors. The final table presents the price forecasts for electricity generation in two formats, 1995 dollars per MMBtu and nominal dollars per MMBtu.

Electricity Generation Price Summary

With the California electricity market undergoing dramatic change in 1998, it is more important than ever to have a well-documented and impartial set of natural gas price forecasts. Both electricity suppliers and consumers need a well-founded set of natural gas price forecasts to base their near-term and long-term planning assumptions. Staff expects this forecast to be used as an important tool to assess the potential for new market competition to move into California as either a consumer or a supplier of energy.

Figures 7, 8 and 9 compare natural gas prices for electricity generation in each service area under the base, high and low price cases. As the figures illustrate, the high case produces natural gas prices ranging from 50 cents per MMBtu higher than the basecase in the early years to 75 cents per MMBtu in the later years of the study period. In the early years of the low case, prices are about 40 cents per MMBtu lower than the basecase and about 60 cents per MMBtu lower in the later years. The high and low price case forecasts for each market sector are detailed in Section V with detailed results included in Appendices I and J.

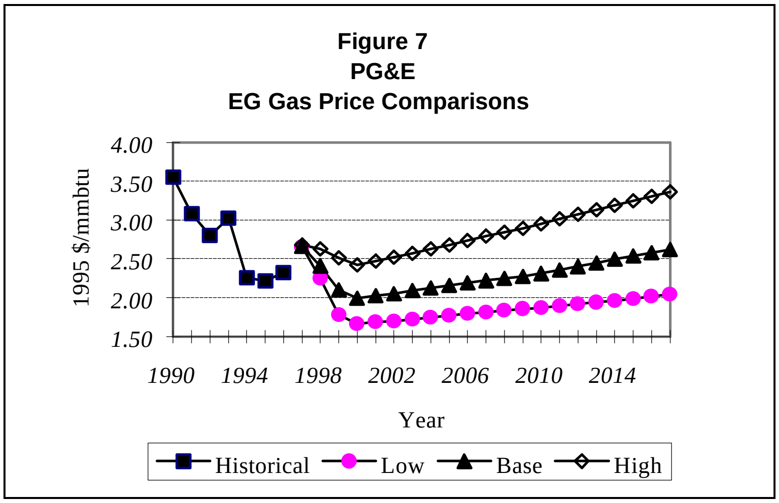


Figure 7
PG&E
EG Gas Price Comparisons

Figure 8
SoCal Gas
EG Gas Price Comparisons

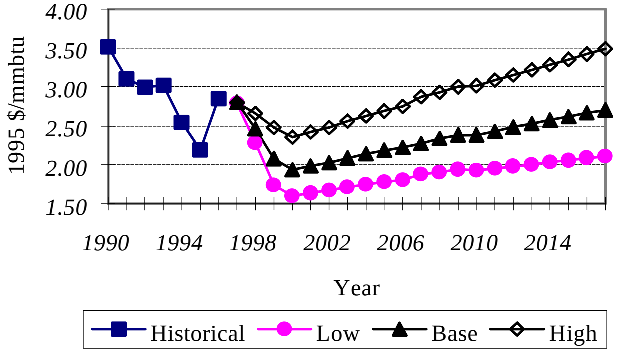


Figure 9
SDG&E
EG Gas Price Comparisons

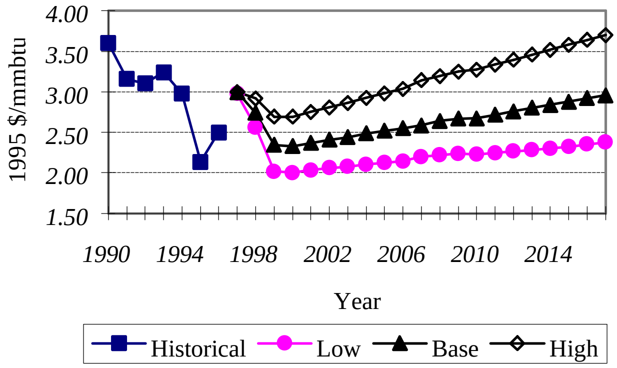
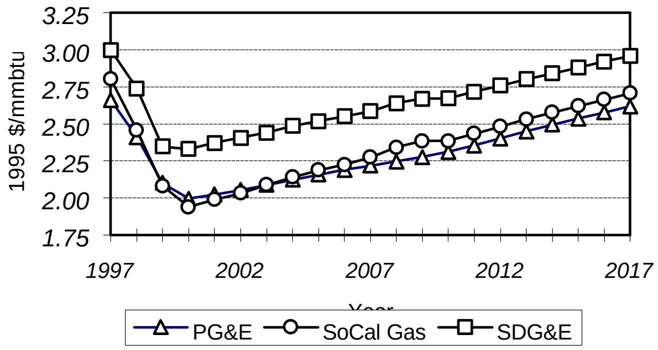


Figure 10 compares natural gas prices for electric generation in the PG&E, SoCalGas, and SDG&E service territories. This analysis indicates that commodity prices will be lower in the northern utility service area, but will have higher delivery costs than in the southern utility service area. Due to additional costs to transport natural gas through the SoCalGas service area, SDG&E natural gas prices for electricity generation are about 30 cents higher than that in the SoCalGas service area. This trend will continue as long as the current pricing structure is maintained. The merger of the two utilities, and unbundling of gas utility services, could change this situation, possibly making electricity generation sector more comparable with prices in the SoCalGas service area.

Figure 10
Base Comparisons
EG Gas Price by Utility Service Areas



Natural gas price forecasts for electricity generation may be used to compare the costs for electricity purchases from other electric generators or independent generators, comparing the costs for various generic electricity generation facilities, and deciding on the least expensive operational patterns. To meet these needs, an aggregated price forecast does not provide enough information for the decision maker. It is important to know what the specific pricing components are.

Like other customer end-use prices, the electric generation end-use price contains three basic components; commodity, interstate transport costs and intrastate distribution costs. Until recently, a portion of the interstate and intrastate transport and distribution costs were levied as monthly demand charges. These charges were considered sunk costs, because they were paid regardless how much natural gas was taken. Remaining costs were volumetric or variable in nature, and were considered part of the electric generation dispatch price. This dispatch price is used to determine whether to generate or purchase the next increment of electricity.

In California, it appears that all three pricing components will be treated volumetrically.[32] For the past several years, this has been the case in the SoCalGas service area. When the SoCalGas-SDG&E merger is completed, SDG&E will most likely shift to an all volumetric electric generation rate. PG&E has proposed in its BCAP[33] to simplify its electric generation rates by converting all its charges to volumetric. Based on this information, staff concluded that all future cost components for electricity generation will be volumetric. Dispatching decisions will be based on the total delivered price to each facility, in conjunction with operational characteristics.

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[32] A portion of the interstate pipeline transport rate could be considered a demand charge. It is such a small part of the total rate that it plays a very minor role, if any, as a dispatching tool.

[33] PG&E BCAP, ***Revised Prepared Testimony Pursuant to the Joint Assigned Commissioner and ALJ Ruling of October 6, 1997***, Application No. 97-03-002, Nov. 7, 1997, pg. 8-20.

Electric generation prices are detailed in the fourth, fifth, and sixth tables of Appendices H, I, and J in each utilities’ series of pricing tables. Two additional electricity generation tables are also provided in the series. Some may need to assess the impact of having a dispatch price which is different from the total price. The tables provide several options. As an example, operators of generation facilities that are merchant function oriented may find that the opportunity cost differentials between generating electricity with their natural gas or selling the natural gas directly as a commodity would be the basis for dispatching their power plants. A California border price may be the basis for making that assessment. The tables provide a commodity and interstate transport price that could be used to make this kind of evaluation.

IV. SENSITIVITIES

The results discussed in the previous two sections were derived using a specific set of assumptions about natural gas resources, transportation rates, pipeline capacities, and demand.

As is the case with all natural gas forecasts, the basecase is not designed to provide the ultimate answer to the future direction of natural gas prices and supplies. Rather, it is simply a best estimate of where staff believes the natural gas market will go during the next 20 years. Given the uncertainty surrounding many of these assumptions, staff prepared a series of sensitivities to test the impact of changing a single parameter on natural gas prices and supplies.

Recognizing that a list of all possible sensitivities would be exhaustive, staff identified five areas which address the most important variables. Each sensitivity is a modification of the basecase with the key variable modified to study the impact of a change in that variable on the price and supply of natural gas. The areas are identified below and a discussion of each sensitivity case follows.

- Power Generation Sensitivities
- General Demand Sensitivities
- Resource Sensitivities
- Technology Sensitivities
- Market-Structure Sensitivities

Power Generation Sensitivities

Electric generation is expected to be the largest contributor to natural gas demand increases during the next 20 years. The actual level of growth, however, continues to be the subject of considerable debate throughout the industry. Two areas which will clearly impact future growth are electric industry restructuring and whether the United States and Canada will reduce greenhouse gas emissions consistent with the Kyoto Treaty.

Experts differ when asked about the impact that electric restructuring will have on future natural gas demand. Many states are at various stages of reforming the electricity marketplace and it is unclear whether political, environmental, or monetary considerations will determine what fuel will become the preferred feedstock for power plants across the continent. In California, natural gas is the feedstock of choice for in-state power plants, while in other areas, coal is the preferred alternative. The push for reduced emissions presently favors natural gas over both coal and fuel oil used for electricity generation. Some experts believe that fuel oil could become attractive to electric generators with the help of new technologies (i.e., reformulated fuel oil) and if natural gas drilling requirements cannot keep up with increased demand for natural gas.[34]

The Kyoto Treaty was the product of an agreement reached between 38 industrialized nations at a global climate change summit held in Japan in late 1997. Among the many items in the treaty is the requirement that the United States reduce carbon emissions by 7 percent below 1990 levels by the year 2012. Canadian emissions are required to drop by 6 percent during that same period. Many feel that electric generation customers, especially those using coal, will be greatly impacted by the agreement. Some industry experts argue that natural gas is the ideal substitute for coal since "each quad of gas combustion produces two thirds the level of carbon of coal, and no other fuel or currently available technology matches cost and carbon emissions combined results." According to one expert, natural gas demand for electric generation will add more than 8 TCF in the United States alone by the year 2010.[35] While the actual increment to natural gas demand for electric generation is debatable, enforcement of the Kyoto Treaty will clearly increase demand for natural gas in North America. The question that remains is whether both countries will abide by the terms of the agreement.

To test the wide range of variation in gas demand as described above, staff ran six power generation sensitivities. The first group of three focuses on national changes in power generation, assuming varying levels of incremental coal demand shifting to natural gas. The second group highlights the impact of changes to in-state power generation.

National Power Generation Sensitivities

In the first case (Low), staff assumes that 25 percent of incremental coal demand used for power generation shifts to natural gas. Higher power generation demand for natural gas raises Lower 48 wellhead prices throughout the forecast period, compared to the basecase. By 2019, prices are seven cents per MCF higher than the basecase. California border prices exhibit similar behavior. Lower 48 natural gas production remains relatively unchanged as incremental energy demand is satisfied with fuel oil. Total supplies to California remain relatively unchanged.

Case two (Medium) assumes that 100 percent of incremental coal demand used for power generation shifts to natural gas. Again, Lower 48 prices increase, compared to the basecase, but the magnitude is much greater than the previous case. By 2019, wellhead prices are 32 cents per MCF higher than the basecase. California border prices exhibit similar behavior. Lower 48 production also increases significantly, especially after 2004. By 2019, Lower 48 production increases 4.1 TCF compared to basecase, reaching 31 TCF. The most significant increase in percentage terms can be found in the Rocky Mountains, where production is 37 percent higher than the basecase. With higher natural gas prices, California gas demand decreases slightly compared to the basecase.

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[34] "Rising Natural Gas Prices are Forecast as More Gas is Used for Power Generation,"*The Energy Report*, January 19, 1998, p. 38.

[35] Canonica, R. "ESAI: Kyoto Treaty will Double Gas Demand for Generation," *Natural Gas Intelligence*, February 17, 1998, p.7.

Case three (High) assumes that 150 percent of incremental coal demand used for power generation switches to natural gas. In other words, all new and some existing power generation facilities using coal now switch to natural gas. Not surprisingly, this assumption generates the highest wellhead prices of the three cases, and highest level of production. Fuel oil consumption also rises to its highest level. In particular, wellhead prices rise 47 cents per MCF above the basecase by 2019. Lower 48 production increases to 32.2 TCF in 2019, with Rocky Mountain production increasing 53 percent above the basecase. Total natural gas demanded in California again decreases slightly as more fuel oil enters the marketplace.

California Power Generation Sensitivities

The three California power generation sensitivities test the impact of the restructured electricity market resulting from the implementation of California Assembly Bill 1890 and Senate Bill 477, passed in 1996 and 1997, respectively. Each of the three cases, that will be described in the following paragraphs, have virtually no impact on Lower 48 natural gas prices and production, so the focus of the discussion will be on California natural gas prices and supplies.

The first case (CA High) assumes that California natural gas demand increases due to restructuring. Competitive electricity markets drive electric generation to cheaper sources in California. Also, nuclear generation facilities are retired at a faster pace than anticipated in the basecase and replaced by natural gas-fired facilities over the 2001 to 2015 time frame. California border prices increase slightly throughout the forecast, eclipsing basecase results by 8 cents per MCF by 2019. Total supplies to California increase by 199 BCF by 2019. Compared to the basecase, Southwest flows to California increase by 4 percent in 2004 and 9-10 percent thereafter. Canadian flows to California increase by 8-9 percent in 2004 and 2009, with the rate of increase slowing to 4 percent in 2014 and 2019. Rocky Mountain flows increase 2 percent in 2004 and 4-5 percent thereafter.

On the other side of the spectrum is case two (CA Low), which assumes that in-state natural gas demand decreases due to electric restructuring. Natural gas used for power generation remains at its level assumed in the year 2000. Renewables, out-of-state imports, and increased conservation measures accommodate increased electricity demand through the remainder of the forecast period. California border prices decrease slightly compared to the basecase, with supplies to the state decreasing by 170 BCF by 2019. Southwest flows to California decrease from 2-8 percent per year beginning in 2004. Rocky Mountain flows increase in 1999 by 8 percent, then decline 1-3 percent during the rest of the forecast. Canadian flows decrease 3-8 percent beginning in 2004.

Case three (CA Transfer) looks at transferring some power generation from Southern to Northern California. This transfer reflects lower natural gas prices in Northern California due to its reliance on less-expensive Canadian supplies, compared to gas from the Southwest regions. In the CA Transfer case, 100 MMCF/D of natural gas demand in Southern California shifts to Northern California beginning in 2000, rising to 200 MMCF/D by 2010 and beyond. California border prices and supplies to the state remain relatively unchanged compared to the basecase. Specific flows to Northern and Southern California change. With increased demand to Northern California, the sensitivity generates increased flows to Northern California from the Rocky Mountains and the Southwest. Not surprisingly, flows to Southern California from Canada drop.

General Demand Sensitivities

While the previous group of sensitivities focused on demand impact by different electric generation assumptions, natural gas demand can be impacted by other sectors as well. Energy consumption requirements for all customer groups can be impacted by changes in building standards, appliance efficiencies, energy intensities, and competition between competing fuels. This section does not attempt to explain the reasons why certain customer sectors may realize gains or losses in demand beyond the basecase assumptions. Rather, it is designed to test how general shifts in demand impact natural gas prices and supplies produced in the basecase.

Aggregate Demand Sensitivities

Two cases were run to test changes in total demand in the United States and Canada. Case one (Demand High) assumes that nationwide demand is 10 percent higher than the basecase. Higher demand pushes Lower 48 wellhead prices higher throughout the forecast period. By 2019, prices are 34 cents per MCF higher. California border prices exhibit similar behavior. Higher demand also results in higher production in the Lower 48. Not all regions experience increases, however. Rocky Mountain production surpasses the basecase by about 25 percent while Permian production declines 7 percent. Total supplies to California increase by 226 BCF in 2019, compared to the basecase. Fuel switching also increases as higher natural gas prices make fuel oil a more attractive fuel option.

The alternative case to be considered is case two (Demand Low), which assumes that the demand for natural gas declines 10 percent below basecase estimates. Lower demand drives Lower 48 wellhead prices down by 23 cents per MCF in 2019, with California border prices moving in the same direction. Production is most impacted in the Rocky Mountains and Gulf Coast regions, which declines 26 percent and 11 percent, respectively. Total supplies to California decrease by 274 BCF by 2019, with all regions supplying the state being impacted.

Core Demand Sensitivities

A second set of cases was run to test changing demand assumptions of core customers. Case one (Core High) assumes that natural gas demand in the core sector exceeds basecase assumptions. By 2015, incremental demand through the Lower 48 reaches 4 TCF. Higher core demand increases Lower 48 and California border prices throughout the forecast. By 2019, Lower 48 wellhead prices are 31 cents per MCF higher than the basecase, with California border prices following in the same direction. Production increases across the Lower 48 with demand reaching 30.8 TCF in 2019, 3.9 TCF higher than the basecase. Total supplies to California increase from all sources, with Rocky Mountain supplies increasing the most in percentage terms (26.2 percent). Higher gas prices also increase the level of fuel oil switching to more than 500 BCF per year by the end of the forecast horizon.

A similar case (NGV High) assumes that natural gas demand for natural gas vehicles (NGVs) exceeds GRI's expectations. GRI's baseline projections indicate that NGV gas demand will increase from 5 BCF in 1995 to 570 BCF by the year 2015. While natural gas powered vehicles have not penetrated the transportation market as originally expected, the potential still exists for the conversion of many fleet vehicles, trucks, and buses. Staff designed this sensitivity to capture the effect of major penetration of natural gas powered vehicles into the transportation market. Staff's sensitivity assumes that demand surpasses GRI's expectations and increases demand by 1.9 TCF in 2015, the equivalent of converting nearly 20 million vehicles to use natural gas as a transportation fuel. The results are similar to the previous case, although the magnitude of change is not as great. Lower 48 wellhead prices increase throughout the forecast, 13 cents higher than the basecase in 2019. California border price movement tracks Lower 48 prices closely. Lower 48 production also increases, with output surpassing the basecase by 2.1 TCF by the end of the forecast. Rocky Mountain production increases 14 percent, while Gulf production rises 7 percent. Total supplies to California increases from all sources. Oil demand also increases, but only 222 BCF per year above the basecase by the end of the forecast.

Resource Sensitivities

Natural gas resource estimates and the prices associated with producing those resources are the major assumptions driving the basecase forecast. Staff's current Lower 48 resource estimate assumes a total resource base of 975 TCF, including more than 300 TCF for reserve growth. Other parties, such as the Potential Gas Committee, USGS, NEB, and Enron, have resource estimates ranging from 870 TCF to as high as 1,425 TCF, with variations explained by the different assumptions made by the respective entities.

As discussed in Section II, the level of reserve appreciation in the NARG model can dramatically impact the direction of a natural gas price and supply forecast. Changes to potential resource estimates for critical producing regions in the U.S. and Canada can also change conclusions reached in the basecase analysis. Given the extensive amount of discussion with other NARG model users and resource experts about appropriate reserve growth and resource estimates, staff generated three sensitivities to test how price and supply projections are impacted by changes to resource assumptions in the Gulf Coast, the Rocky Mountains, and Canada. A description of each case follows.

Low Resource Sensitivity

The Low Resource sensitivity assumes that reserve growth in the Gulf Coast, the Rocky Mountains, and Canada is 25 percent lower than in the basecase. This change decreases the level of available resources by a combined 32 TCF during the forecast period.

Not surprisingly, lower resource availability leads to lower production and higher prices throughout North America. Lower 48 production declines by 186 BCF in 1999 and 835 BCF in 2019. Sharp declines in Gulf Coast production relative to the basecase are offset somewhat by production increases in most other Lower 48 supply regions. Canadian production declines 35-245 BCF in aggregate over the forecast horizon, although increased Sable Island and British Columbia production offset decreases from Alberta.

Lower 48 wellhead prices increase 24-50 cents per MCF in the Low Resource sensitivity. Canadian wellhead prices also rise 22-47 cents per MCF. California border prices increase 21-45 cents during the forecast period.

Regarding flows to California, the sensitivity produces little change in flows compared to the basecase. However, British Columbia gas gains market share from Alberta production. British Columbia gas accounts for 14 percent of Canadian supply to California by 2019, compared to 9 percent in the basecase. A slight increase in oil switching, beginning in 2014, comes at the expense of Southwest gas flows.

Gulf High Resource Sensitivity

Recent drilling activity in the deepwater region in the Gulf of Mexico has produced a plethora of natural gas resource potential not considered in resource analyses performed before 1997. The Gulf High sensitivity case assumes that 100 TCF of additional resource is added to the federal offshore water’s cost curve. With the incremental change, total resource potential in federal Gulf Coast waters assumed in this sensitivity is 195 TCF.

Lower 48 production in this sensitivity increases by 216-485 BCF during the forecast, offset by decreased Canadian production and LNG receipts. Gulf production increases 757 BCF in 1999, increasing to 1.59 TCF in 2019. The Lower 48 region most adversely affected is the Rocky Mountains, which experiences a 157 BCF reduction in 1999, and a 755 BCF reduction in 2019. Production from all other Lower 48 regions declines also, but not as significantly as the Rockies.

With much more Gulf Coast gas available at lower prices compared to the basecase, wellhead prices decline for all regions. For the Lower 48, the aggregated wellhead price declines 16-34 cents per MCF. Canadian wellhead prices also decline 8-16 cents per MCF.

As Gulf Coast supplies displace some Permian supplies to midwest and mideastern markets, Southwest flows to California increase 65-98 BCF over the forecast horizon. All other regions supplying gas to California decline compared to the basecase. Canadian flows to California decrease by 23-52 BCF.

Canada High Resource Sensitivity

The Canada High sensitivity case increases Alberta potential resources by 25 percent and doubles Sable Island resource availability. The combined change adds 51 TCF of resource potential to the Canadian potential resource estimate used in the basecase.

Canadian production increases by 369 to 555 BCF during the forecast period, almost entirely offset by decreased Lower 48 production. Virtually all of the increase in Western Canada can be found in Alberta. Sable Island production is twice the basecase estimate in 2004 (105 BCF versus 55 BCF), reaching 192 BCF by the end of the forecast period (compared to 149 BCF in the basecase).

With increased production, comes increased exports to the United States. Canadian exports to the Lower 48 peak at 4.44 TCF in 2019, about 520 BCF higher than the basecase. With more resources available at lower prices, Canadian wellhead prices decline 15-32 cents per MCF during the 20-year period ending 2019. Lower production in the United States generates a 3-5 cents per MCF decline in Lower 48 wellhead prices. California prices drop 7-14 cents per MCF.

Canadian gas flows to California increase by 61-115 BCF, all from Alberta. Most of the increase in Canadian gas flows to California is offset by decreases in Southwest flow (44-70 BCF). Rocky Mountain and California gas flows both decrease slightly in this sensitivity. To accommodate the increased gas flows from Canada, additional capacity will be needed at Malin in 2004, rather than 2009 as projected in the basecase.

Summary of Resource Sensitivities

Figures 11 and 12 compare each of the three resource sensitivities with the basecase. While each case exhibits slight variations in Lower 48 production from the basecase, wellhead price variations are much more significant. As Figure 12 illustrates, the cases generate a $0.42 price range in 1999 from the lowest-priced (Low Resource sensitivity) to highest-priced (Gulf High) case. The range increases to $0.84 per MCF by the year 2019. In percentage terms, the highest-priced case is 31 percent above the lowest case in 1999, and 49 percent higher in 2019. By comparison, the range of differences between Lower 48 production is 3-5 percent.

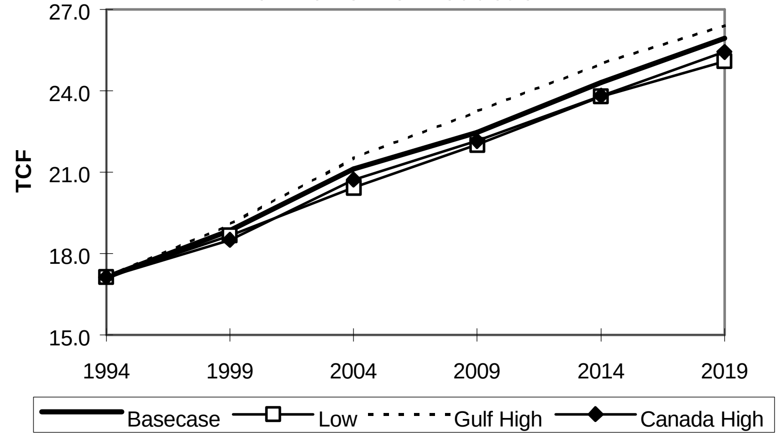
Figure 11
Impact of Different Resource Assumptions
on Lower 48 Production

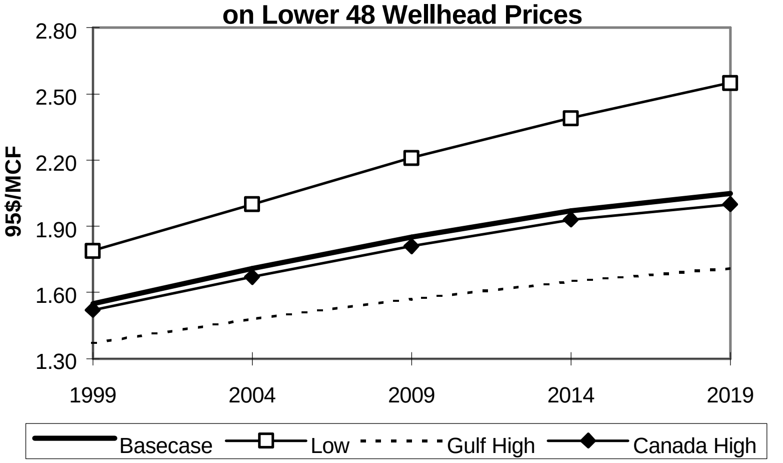
Figure 12
Impact of Different Resource Assumptions
on Lower 48 Wellhead Prices

Technology Sensitivities

Section II briefly described how staff uses the NARG model to account for technological enhancements which reduce the out-of-pocket cost of finding, drilling, and producing natural gas. Staff applied reductions for the application of 3-D seismic and slim hole drilling, as well as for drill bit improvement technologies. Different from past forecasts, a 20 percent reduction factor was generically applied to all cost curves in the model due to expected cost reductions from technologies, such as laser drilling, which are not yet in place. This group of sensitivities tests various levels of cost reductions, assuming higher and lower technology impacts compared to the basecase.

No Technology Enhancements

The “No Technology” case assumes that drilling and exploration technologies remain at present levels. Thus, resource costs assumed for each cost curve in the NARG model do not decline due to technological improvements. The impact on prices in the Lower 48 and Canada over the forecast horizon are dramatic. Lower 48 wellhead prices increase by 33-59 cents per MCF compared to the basecase. Canadian prices rise by 29-57 cents per MCF. California border prices increase by 32-62 cents per MCF.

The high prices in this case cause a decline in Lower 48 and Canadian production as LNG and fuel oil become competitive options for noncore customers. Production decreases in all regions in the Lower 48 and Canada, except for the North Central region. Little change in flows to California is apparent, except for approximately 90 BCF of fuel oil switching in 2019. It should be noted that fuel oil switching in California comes at the expense of Southwest and California supplies.

Rapid Technology Enhancements

The antithesis of the “No Technology” case is the “Rapid Technology” sensitivity, which assumes that technology costs decline to 10 percent of current values for all resources across North America. For purposes of comparison, basecase technology cost reductions range from 45-60 percent below current levels.

Like the previous sensitivity, this case dramatically impacts wellhead and California border prices. Lower 48 wellhead prices decline by 41-73 cents per MCF, while Canadian prices drop by 38-77 cents per MCF during the 20-year forecast period. California border prices decline by 44-87 cents per MCF. Regarding flows to California, increased Southwest flows go to Northern California, offsetting reduced Canadian flows at Malin. San Juan Basin gas also flows to Southern California, offsetting reduced Permian flows at Blythe. In-state production remains relatively unchanged, while Rocky Mountain flows decline slightly.

Resource Development Enhancements

The third technology sensitivity assumes that resource development takes only one year to develop, rather than the three years assumed in the basecase. This case lowers Lower 48 wellhead prices by 12-17 cents per MCF during the forecast, while Canadian prices drop by 10-18 cents per MCF. California prices also decline, consistent with Lower 48 price drops. While production in the Lower 48 increases by 83-352 BCF during the forecast, little change in flows to California or Canadian production occurs.

Market-Structure Sensitivities

The final set of sensitivities focuses on the current pipeline configuration in the Lower 48 and Canada by testing the impact of modified pipeline assumptions on basecase results. The first two answer a global question about pipeline expansion and rate design. The final case reviews a specific proposal to significantly reduce southern system capacity on the El Paso system and its impact on California supply availability and price.

Pipeline Addition Sensitivity

Pipeline expansion projects, too numerous to mention, have been proposed across North America and Canada during the past couple of years. CERI recently reported that 52 new pipeline and expansion projects were planned to add up to 26 BCF/D of capacity to the continental grid by the year 2000.[36] Many of these expansions are targeted to serve markets in both the East North Central region, mid-Atlantic, and New England demand regions. Canadian projects are a key component, as Canadian companies attempt to increase their level of exports to the United States. While some of these projects will never materialize, the sheer number of proposals raises speculation about how the pipeline network will change over time and how prices and flows will shift as a result.

Although the NARG model allows pipeline corridor capacity to expand to meet market demand, it does not consider adding new transportation corridors which provide a new link between supply and demand regions. This affect must be evaluated by adding a new link. The Pipeline Addition sensitivity considers the impact the proposed Alliance Pipeline project will have on natural gas prices and supplies. The Alliance project is a proposed 1.2 BCF/D pipeline extending 1900 miles from Eastern British Columbia to the Chicago area. It will allow British Columbia gas to directly access midwestern and eastern markets in the United States for the first time. Alberta gas also accesses the new link. Staff introduced a new link in the NARG model to reflect the new corridor.

Compared to the basecase, Lower 48 wellhead prices remain relatively unchanged, decreasing by about 3 cents per MCF during the forecast period. California border prices increase slightly, approximately 2 cents per MCF in 2019. While production in the Lower 48 remains relatively unchanged., Canadian production increases by about 200 BCF per year, the bulk going to U.S. markets.

Incremental Expansion Sensitivity

The question of rolled-in versus incremental rate treatment for pipeline expansions was a major ratemaking issue addressed during the mid-1990s. FERC did so to develop a straightforward procedure to approve pipeline expansion projects, while reducing the regulatory burden on all parties. Current FERC policy allows interstate pipeline companies to roll in expansion costs, as long as the post-expansion transmission rate is not more than 5 percent above pre-expansion rates. Otherwise, incremental rate treatment is adopted, creating a two-tiered set of rates for pre-expansion and incremental customers.

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[36] Mahan, R. and Morton, K. “Natural Gas Pipelines: New Pipelines and Expansions,” Special Report 97-2, April 1997.

The NARG model treats all pipeline expansion as incremental; however, any incremental capacity exceeding the base level by more than 15 percent will result in a higher “rolled-in” per unit price for transporting gas from supply to demand region. This sensitivity addresses the inconsistency with FERC’s current policy by assuming that all pipeline expansions meet the “5 percent” rule. No additional transportation costs are applied to any pipeline corridor that requires expansion, regardless of how much capacity is needed. Similar to the basecase, underutilized capacity is discounted.

In general, the new and low cost supply regions benefit significantly in this sensitivity. Rocky Mountain supplies to California increase by about 240 BCF per year, while Southwest and Canadian production both decline by about 100 BCF. Lower transportation costs from the Rocky Mountains reduce delivered prices at the California border by 18 cents per MCF. Canadian and Southwest prices also drop, 10 to 12 cents per MCF by 2019. Overall prices at the California border increase by approximately 5 cents per MCF in the early periods of the forecast, but reverse that direction and drop 5 cents per MCF in 2019.

El Paso Southern System Sensitivity

Staff’s final sensitivity recognizes reduced demand for Permian gas at the California border resulting from increased San Juan Basin supplies to the state. In this case, all flows through the Ehrenburg delivery point to California come from the San Juan Basin via the Havasu Crossover. The El Paso line no longer flows Permian gas to California on the southern part of its system, but does use it to serve markets in southern Arizona and New Mexico as well as emerging Mexican markets. Supplies from the Havasu Crossover may flow east along the southern system to serve markets east of California.

Compared to the basecase, Lower 48 wellhead prices remain relatively unchanged through the forecast period. California border prices increase slightly, rising 5 cents per MCF by 2019. The total supply picture to California remains unchanged with San Juan supplies displacing Permian supplies at the California border.

V. INTEGRATED MARKET ANALYSIS

During the development of the ***1993 Natural Gas Market Outlook***, staff developed two broad scenarios: Competitive America and Natural Gas Dominance. The two scenarios examined plausible variations of the basecase forecast. For the ***1995 Natural Gas Market Outlook,*** staff reevaluated the Competitive America and Natural Gas Dominance scenarios, and updated input assumptions. Scenario planning, a tool used to develop possible and plausible alternative future outcomes, assists planners working with uncertainty. However, for the current report, staff utilized a different approach to uncertainty analysis.

Using a combination of critical input parameters, staff constructed two integrated sensitivities which examine long-term market conditions. Two important factors distinguish integrated sensitivities from scenarios. First, scenarios assemble “worlds” where the interaction of the participants lead to various outcomes, while integrated sensitivities, taking a more restricted view, answer the question of “what if all the events associated with model input parameters simultaneously occurred?” Second, in scenarios, the view of the world determines the model inputs, whereas, in integrated sensitivities, the analyst selects -- sometimes, arbitrarily -- the critical input parameters.

Integrated Sensitivity Design

The energy industry is undergoing major changes. Electricity restructuring is nearing full implementation; the CPUC is pushing further natural gas deregulation, major market hubs are developing in many locations on the North American continent, and financial markets are playing an expanding role in price risk management. This sensitivity analysis, motivated by the large variation in natural gas prices observed in the past, attempts to capture these market uncertainties.

In late 1970s and early 1980s, natural gas prices climbed to record highs. By the mid- to late-1980s, deregulation swept the natural gas industry and competition forced prices to record lows. In the 1990s, energy financial markets rose to prominence. Instruments, such as futures and forward contracts, options, and swaps, are now commonplace in energy markets. Uncertainty sustains the need for these financial tools.

Staff identified three *critical uncertainty parameters*: noncore natural gas demand, supply resources development, and technology advances. The sensitivities of the basecase forecast to each of these factors was addressed in Section IV. The combination of the critical uncertainty parameters can produce many possible outcomes. However, to test the full range of the natural gas price forecast, staff constructed two mega-sensitivities: the **Integrated Low Price** case and the **Integrated High Price** case. Rather than being forecasts of the future, the mega-sensitivities represent a framework whereby staff can analyze natural gas prices and availability subject to a variety of uncertain constraints.

Critical Uncertainty Parameters

Using the critical uncertainty parameters, staff delineated competing market conditions and then translated these conditions into assumptions for modeling the mega-sensitivities.

Noncore Gas Demand

Presently, the California electricity industry is facing major restructuring. Electricity power generators, one of the largest natural gas consumers in the state, soon will be facing increased competition from non-traditional power suppliers. Natural gas will compete against electricity for at least some energy demands. As a result, natural gas demand will deviate from its previously projected path. Further, efficiency innovations in the end-use sector will suppress gas demand, creating unpredictable price pressures. Also, action by the CPUC in the core sector will add further uncertainty as competition between consumer groups increase.

The regulatory environment and economic conditions impact both natural gas producers and consumers. Positive economic conditions lead to higher disposable income, which in turn lead to greater demand for goods and services. Businesses invest and expand as they meet the increased demand and overall energy consumption -- natural gas, oil, electricity -- rises. Energy usage will rise and fall with the business climate. However, rising energy consumption may lead to environmental threats. Cleaner burning natural gas will partially replace residual oil and coal as the industrial and power generation sector seek more environmentally-friendly fuels. Policy makers, though, must strike a balance between concerns for the economy and concerns for the environment.

Technological Advances and Resource Development

Technology will also affect production and consumption of natural gas. An efficient pipeline network connects end-users to the North America's abundant natural gas resources. The basecase forecast includes an estimate of the most likely technological advances, resulting in a reduction of the capital costs for exploration and development of resources. Staff did not directly change the technology parameter in the NARG model.

Technological advances in resource development and production will certainly affect the future. Most observers agree that the resource base will continue its expansion. However, the rate of expansion depends upon the rate of technological advances. As a result, the initial size of the resource base remains unchanged in the model. What is uncertain about gas supply is the extent to which technological advances will expand the resource base. The mega-sensitivities use the *reserve appreciation parameter (RAP)* to represent both changes in resource development and in technology advances. The inclusion of the RAP produces more resources at lower costs.

Mega-sensitivities Assumptions

Integrated High Price

In many jurisdictions, gas use increases as a result of air quality requirements which specifically restrict "oil burn," and reduce "coal burn." Many electricity generators, seeking a cleaner burning fuel, switch to natural gas for both existing facilities and new additions.

Further, decreased technology advances lead to lower than expected natural gas resource additions. Producers adjust their operations to keep up with demand. Total energy demand is stable, but natural gas gains significant market share as a result of the policy guidelines.

Integrated Low Price

Rapid innovations in natural gas finding and development raise reserves to record levels. Technology advancements increase resource availability and decrease the time between discovery and actual production. High efficiency gas-fired generation technology and a competitive electricity market reduce gas demand for electric generation. Efficiency innovations at the burner tip (conservation and demand-side management) diminish growth in energy usage. Overall energy demand rises slowly. Inter- and intra-fuel competition is strong throughout the planning horizon. Natural gas loses market share to competing fuels.

Integrated Sensitivities Parameters

The final step in this analysis required the quantifying of the sensitivity conditions for use in the model. The NARG model contains parameters which can be manipulated to represent the specific market conditions defined in the preceding discussion. Each critical uncertainty translates into one or more model parameters.

Table 29 lists the specific parameters and summarizes the assumptions made for the Integrated High and Low Price cases. The table also compares the input assumptions for each case with the basecase.

Results of Integrated Market Analysis

In the Integrated Low Price case, decreased noncore demand and greater supply availability depress Lower 48 prices throughout the forecast period. By 2019, prices are $0.47 per MCF lower than the basecase.

TABLE 29
NARG MODEL INPUT ASSUMPTIONS

Parameters	**Integrated High Price**	**Basecase**	**Integrated Low Price**
Natural Gas Resources			
Reserve Appreciation	Lowered the basecase reserve appreciation parameter by 25%	Set at rates between 0.5% and 4%	Raised the basecase reserve appreciation parameter by 25%
Lag Parameter	Same as basecase	Set at three years	Lowered to one year
Natural Gas Demand			
Noncore	10% Higher than Basecase	9.3 TCF/Yr in 1999 12.4 TCF/Yr in 2009	5% Lower than Basecase

In the Integrated High Price case, higher noncore demand and decreased supply availability push Lower 48 prices up throughout forecast period. By 2019, prices are $0.83 per MCF higher than the basecase. Figure 13 below, graphically illustrates the wellhead prices of the three cases. California Border prices, shown in Table 30, exhibit similar behavior to that described above.

Figure 13
Basecase and Integrated Sensitivities Comparison
Lower 48 Wellhead Prices

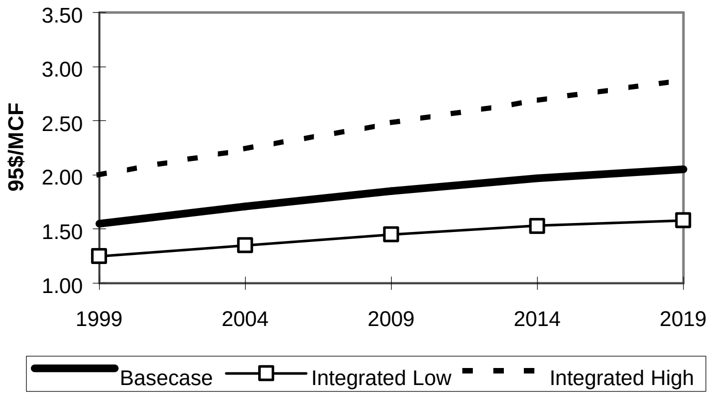


TABLE 30
BASECASE AND INTEGRATED SENSITIVITIES COMPARISON
CALIFORNIA BORDER (CITYGATE) PRICES
1995$ PER MCF

	1999	2004	2009	2014	2019
Basecase	1.68	1.88	2.05	2.27	2.46
Integrated Low Price	1.37	1.51	1.64	1.75	1.87
Integrated High Price	2.11	2.41	2.71	3.03	3.34

Table 31 below illustrates the growth rates for the three cases. Over the forecast horizon, wellhead prices in the Lower 48 and Canada grow at about 2 percent. California border prices exhibit a similar growth rate. In all cases, the Integrated High Price case exhibits the highest growth rate.

TABLE 31
BASECASE AND INTEGRATED SENSITIVITIES COMPARISON
ANNUAL GROWTH RATES
(Shown in Percentage Terms)

	Basecase	**Integrated High Price**	**Integrated Low Price**
Annual Growth Rates (1999 to 2019)			
Lower 48 Wellhead Price	1.4	1.8	1.5
Canadian Wellhead Price	2.1	2.5	1.5
California Border Price	1.9	2.3	2.0

In the Integrated Low Price case, Lower 48 production remains relatively unchanged. However, the market shares of the major producing regions shift. Rocky Mountains and Gulf lower output, while Anadarko, San Juan, and Permian all increase production. By 2019, total supplies to California decrease by 105 BCF. Southwest supplies fall by about 2 percent, Rocky Mountains by about 10 percent, and Canada by about 5 percent.

In the Integrated High Price case, Lower 48 production exceeds the basecase in the early years of the forecast period. However, after 2014, production falls below the basecase. By 2019, Lower 48 production is about 7 percent lower. Gulf and Permian lower natural gas output, but Rocky Mountains production climbs to 4.2 TCF per year in 2019, a 29 percent increase. Table 32 compares the relative market shares of California's major supplies regions for the year 2004.

In both sensitivities, production allocation differs from the basecase. In the Integrated High Price case, Southwest and Rocky Mountains experience declines, but Canadian supplies to California increase by about 7 percent. However, in the Integrated Low Price case, Southwest supplies increase, while all other regions experience a decline.

TABLE 32
BASECASE AND INTEGRATED SENSITIVITIES COMPARISON
CALIFORNIA MARKET SHARES
(Shown in Percentage Terms)

	Basecase	**Integrated High Price**	**Integrated Low Price**
Market Share of California Supplies (2004)			
Southwest U.S.	48.7	45.7	50.8
Canada	25.1	28.2	24.2
Rocky Mountains	12.1	11.8	12.0
California	14.2	14.4	13.1

The difference in gas supplies can be seen in Figures 14 and 15, which respectively show the Integrated High Price and Integrated Low Price cases' deviation from the basecase. In the Integrated High case, gas supplies to California from all regions mostly increase throughout the forecast period. The increase varied between 0.01 TCF and 0.13 TCF per year. However, late in the forecast period, Canadian supplies decreased relative to the basecase. By 2019, Southwest supplies lag behind the basecase by about 0.08 TCF. In the Integrated Low Price case, lower demand produces lower gas supplies to California. Throughout the forecast period, with few exceptions, supplies to California in the Integrated Low Price case fall behind basecase supplies by about 0.05 TCF per year.

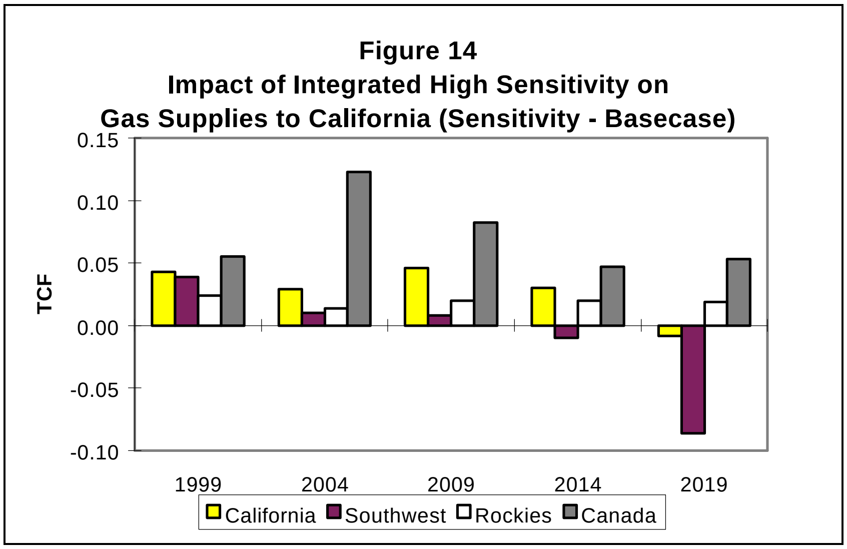


Figure 14
Impact of Integrated High Sensitivity on Gas Supplies to California (Sensitivity - Basecase)

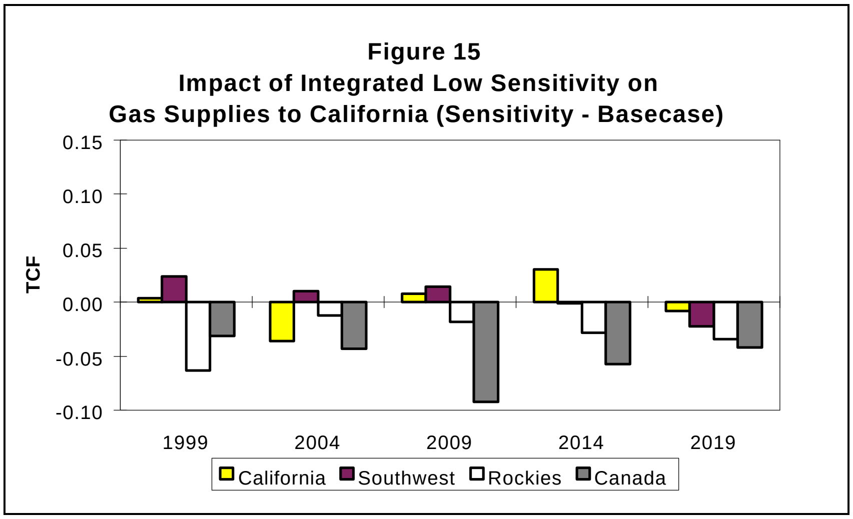
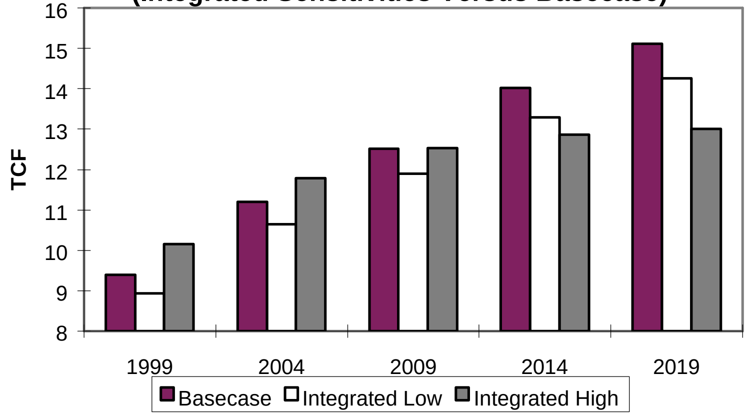


Figure 15
Impact of Integrated Low Sensitivity on Gas Supplies to California (Sensitivity - Basecase)

Staff identified noncore gas demand as a critical uncertainty parameter. Consequently, Figure 16 illustrates this parameter for the three cases. One final result that emerged from this analysis, was the significant fuel switching, which occurred in the Integrated High Price case. Oil demand skyrockets, reaching 3.7 TCF per year -- three times the 1994 level -- by 2019. Increased oil demand partially compensates for the lower gas demand. Total gas demand in the Integrated High case surpassed both the basecase and the Integrated Low Price case.

Figure 16
Lower 48 Noncore Gas Demand Comparison
(Integrated Sensitivities Versus Basecase)



VI. ISSUE FOCUS: THE IMPORTANCE OF NATURAL GAS MARKET CENTERS

Regulatory reforms have revolutionized the way natural gas is marketed throughout North America. Increasing competition among producers, transporters, and distributors has created market centers or "hubs" where natural gas is bought and sold competitively. As further restructuring of the natural gas and electricity markets evolves on a federal and state level, future energy markets will witness a combination of natural gas and electricity hubs or centers where the two forms of energy will be traded, perhaps simultaneously.

Natural gas market hubs can be useful to market participants in several ways: 1) improving transportation efficiency, 2) providing load balancing flexibility, 3) utilizing storage more efficiently, 4) enhancing customer choice, and 5) increasing producers' ability to market their gas. Technology, in terms of information access and dissemination, can only further this goal of ensuring a more competitive and efficient market. "Real-time" information access combined with the flexibility to purchase natural gas at short notice has enhanced the ability of suppliers to provide gas supplies to consumers through displacement. It also has allowed marketers to serve the needs of their clientele by providing them with a competitive package of services, while concurrently, maximizing their own margins.

This section begins with a review of how natural gas market hubs function in today's competitive environment. It concludes by providing a comparison of price differentials and pipeline capacity utilization between various market centers or hubs. The projections are based on the basecase analysis described in earlier sections of this report.

Regulatory Progress

Both natural gas and electricity markets have undergone significant regulatory reforms over the past two decades. Table 33 displays some of the significant events that have shaped these two industries. The evolution of market hubs and centers has resulted from the increased emphasis on competition in the energy industry.

Natural gas supply and interstate transportation services have been deregulated to a large extent. Regulation of natural gas markets within individual state boundaries is slowly changing with market incentives and reforms being implemented to enhance the competitive aspects of the markets, as has been done in the interstate markets. California recently began addressing the issue of competitive natural gas markets and consumer choice programs for all consumers, including residential and small commercial customers. The electricity industry in California, by comparison, is further along in addressing these issues and has already embarked on a dramatic restructuring of its marketplace, breaking down the vertically integrated structure of the utility, separating the generation, transmission and distribution functions. As natural gas restructuring proceeds, staff argues that the level of competition in both markets are converging.

TABLE 33
MAJOR REGULATORY MILESTONES
IN THE NATURAL GAS AND ELECTRICITY INDUSTRIES
DURING THE PAST 20 YEARS

Natural Gas	NGPA passed. Wellhead price decontrol begins.	Markets develop for spot purchases. Direct sales increase. Unbundling services begin. Take-or-pay issues arise with settlement costs shared among industry.	Spot pricing and sales increase. Shift from long-term contract to short-term and spot purchases. Market centers develop.	GISB standards developed. Futures markets take stronger hold. Natural Gas Strategy unfolds in California.
Time	**1978**	**Mid-80s**	**Early-90s**	**Mid-90s**
Electricity	Implementation of PURPA. QF's sell power to utilities at avoided costs.	Competitive bidding for new capacity. QF contracts develop.	Electronic bulletin boards appear. Wholesale open access begins. Electricity restructuring concepts pushed in California and other states.	FERC Orders 888/889 issued. Electricity open access begins. Service unbundling; OASIS. Recovery of Stranded Costs.

Development of Market Hubs and Centers

The fundamental driving forces towards restructuring and competitive markets is the integration of markets and the commoditization of energy products. For example, in the old regulated era, markets did not have natural gas procurement choices, but instead relied on pipelines for this service. When pipelines were relieved of this obligation, in the mid 1900’s, their customers found an increasing number of options available for them to make alternative purchases at cheaper prices. At the same time, producers saw benefits of improving their economic conditions by choosing when and where to sell their natural gas at the most beneficial price.

The concept of consumer choice has slowly evolved to the current competitive field. The level of competition has been aided by restructuring or regulatory reforms through a variety of ways such as discussed above. Regulators have implemented ways by which producers, transporters and consumers can exercise their choices to achieve economic benefits. Barriers, such as regulated wellhead prices, tariff limitations on pipelines, limited access to supplies due to lack of alternative options, receipt and delivery point inflexibilities, and long-term contractual obligations that inhibit players from exercising their choices, have either been removed or reduced.

With these new market developments, certain geographic locations became logical centers, or market hubs, for natural gas suppliers and buyers to arrange deals. These emerging market hubs become single points or market centers where all players -- producers, transporters, and consumers -- can buy or sell natural gas using either long-term or short-term contractual arrangements. A simple market hub conceptually consists of two or more suppliers, two or more consumers, and a storage facility all linked by interconnecting pipelines. In reality, actual hubs need not possess all these characteristics, and the number and type of participants can vary. For example, a market center with only one producer and one storage facility, but two or more consumers, may also represent a market hub. In this case, the producer has options about whether to sell gas or put it into storage, while consumers can choose between buying the gas from the producer or taking it out of storage, depending on price.

Normally, at a market hub, producers, consumers, and marketers representing both small and large consumers, are involved in the gas transactions. When the marketer is involved, it is not essential that the producer knows who purchases the gas or the consumer knows who produces the gas. The marketer buys from several producers and sells to several consumers. In today's markets, marketers are represented by clearinghouses, brokers, hub managers, storage facility operators and aggregators. It is not unusual for several independent transactions to occur after natural gas is sold by a producer and before it is bought by a consumer.

Impact of Hubs or Centers on Pricing and Reliability

Market hubs clearly impact the price at which natural gas is traded. The producers have the option of selling to the high bidders, while the consumers have the option to go to the cheapest seller. Through the use of electronic bulletin boards and other information dissemination mechanisms, information becomes more transparent to all market participants. This enhances competition among sellers and buyers. Transactions can and do occur for various contract periods, such as long-term contracts and spot or daily contracts. It is probable that these market transactions in the future might occur as frequently as on an hourly basis. Today, the choices in competitive markets are available only to large gas consumers, such as industrial customers, and to some extent, to smaller customers through core aggregators or marketers. The number of players will increase as small and large consumers gain better access to competitive service options.

The fact that there may be several producers supplying the hub is sufficient for consumers to be ensured that they will be able procure supplies at market-clearing prices. In this instance, consumers bear the risk in deciding for how long and how much natural gas they need. On the other hand, producers have the advantage that there will be a consumer to purchase their gas, if the sale price is right. Producers bear the risk in deciding how low to price their gas to ensure that there are takers for their supplies. This dual combination of producers and consumers weighing their individual risks ensures that natural gas is bought and sold at the most economical *market-clearing prices*, to the benefit of both parties.

The question of reliability arises when a producer or consumer has to decide on the level of risk involved that he/she can bear in choosing to hold off or buy gas at a specified time. The consumer's perception of the direction in which the market would move in the future will dictate the level of risk that would be assumed by an immediate decision. In an ideal market, collection of such decisions sways the reliability factor such that consumers manage their risks by either buying gas at the available price, or waiting until they can get a better price. The same is true for producers who manage their risks by either selling at the market price, or holding off with the expectation that prices rise. These buy-sell decisions impact the market place and determine the clearing prices or spot prices at the market hubs.

As discussed above, a natural gas market hub or a market center is created at any point where several pipelines and storage facility connections meet. The natural gas pipeline system in the North American continent is a complex grid, containing over 40 established market centers. Most of these centers are also linked to storage facilities. Figure 17 displays geographic locations of major market centers or hubs across North America. The majority of the operating centers are presently located in the Gulf region, with most operating since 1994. Hubs generally are located in close proximity to supply regions or demand centers. The next section looks at future market clearing prices and price differentials in comparison to a "Henry Hub clearing price" as predicted by the NARG model, at various supply and demand centers in the Lower 48.[37]

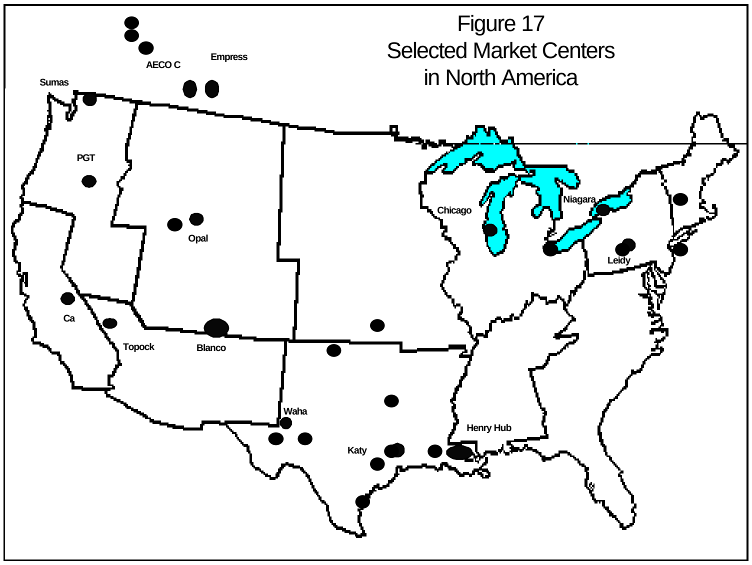


Figure 17
Selected Market Centers
in North America

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[37] Henry Hub, located in southern Louisiana, is a market center with 12 pipelines and has direct access to storage. The Hub is used as the delivery point for natural gas futures traded on the New York Mercantile Exchange.

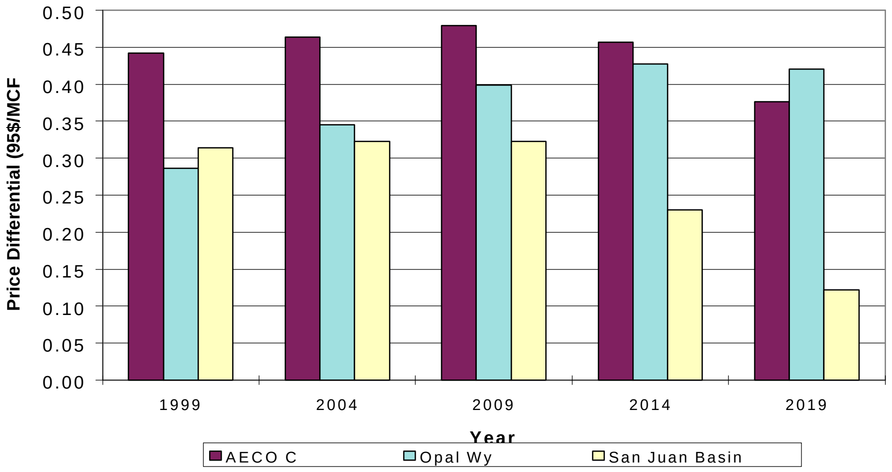
Natural Gas Price Differentials at Various Market Centers

This section compares the price differentials for various supply and demand market centers through out the United States and Canada. The comparisons are based on the basecase results arrived by using the NARG model, in support of the adopted natural gas price forecast. The price differentials are compared using a proxy of the Henry Hub price as the basis.[38] The differentials represent the Henry Hub price minus the hub or market center price.

Please note that these results are for market trend illustrative purposes only. The NARG model predicts long-term equilibrium prices only, while the Henry Hub prices more typically represent short-term market conditions.

Figure 18 compares the price differentials of Alberta (AECO C), Rocky Mountain (Opal Wyoming), and San Juan supply regions with the Henry Hub price. Alberta's abundant resources help maintain the differential from Henry Hub at around 40-45 cents per MCF throughout the forecast horizon. Supplies from the Rocky Mountain region indicate an increasing differential, i.e. the Rockies being a relatively new supply region, is able to maintain its price lower than the Gulf supply region. San Juan supply region on the other hand maintains the differential as observed today, for the next decade. The current abundant supplies of low cost coalbed methane maintains the present based differential. However, beyond the next decade, as the coalbed methane resources reach maturity, the difference decreases and prices between the Henry Hub and the San Juan region converge closer to each other.

Figure 18
Regional Price Differentials:
Henry Hub Price Minus Alberta, Rocky Mountains, or San Juan Prices



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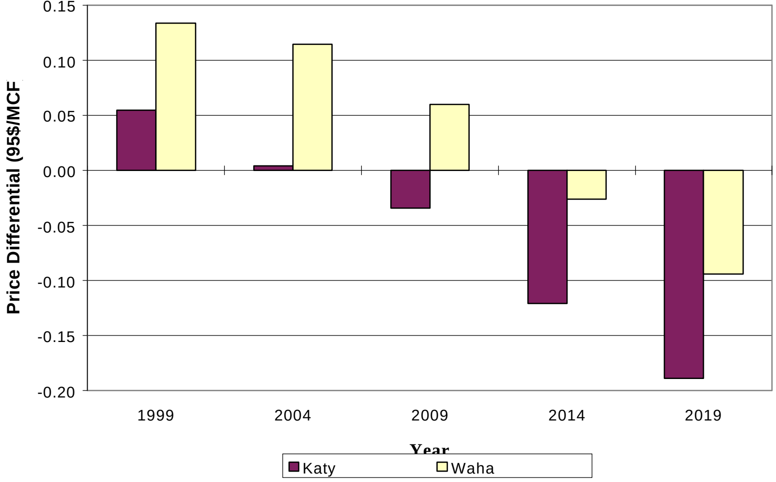
[38] While the Henry Hubb is directly represented in the NARG model, the price was approximated by adding $0.10 per MCF to the offshore Gulf Coast wellhead price.

Figure 19 shows the price differential for Katy and Waha supply centers in comparison to Henry Hub prices. While prices in these two regions are below the Henry Hub prices in the near term, increased offshore supplies from the Gulf region maintains the Henry Hub prices at a relatively flat growth rate. Prices for onshore supplies from both Katy and Waha increase over time, eventually rising above the Henry Hub price levels by the end of the forecast horizon.

Figure 19
Regional Price Differentials
Henry Hub Minus Katy and Waha Supply Prices



Figures 20 and 21 compares price differentials at various demand market centers to the Henry Hub price. Figure 20 shows the price differentials in the Northeast markets in Pennsylvania and Niagara demand centers. As the figure illustrates, market prices in the Northeast demand region increase over time compared to the Henry Hub price. Two factors lead to this increasing differential. First, as pipeline capacity to transport natural gas to these centers increase, mainly from Western Canada supply basins, Canadian producers will be able to capture the high growth markets, achieving better returns vis-à-vis their conventional markets. Second, while the transportation capacity utilization from Gulf to the Northeast markets is significantly lower today than utilization on Canadian lines to the region (65 percent compared to nearly 100 percent), demand in this region grows over time, increasing the level of capacity utilization, and reducing the discounts enjoyed by consumers in this region. Figure 21 compares the price differentials in the West North Central and East North Central markets to the Henry Hub price.[39]

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[39] It should be noted here that the price differentials are for the relatively large demand regions and consider the weighted average prices from all supply sources serving this demand region. Hence, they may not be reflective of current price postings at each market center.

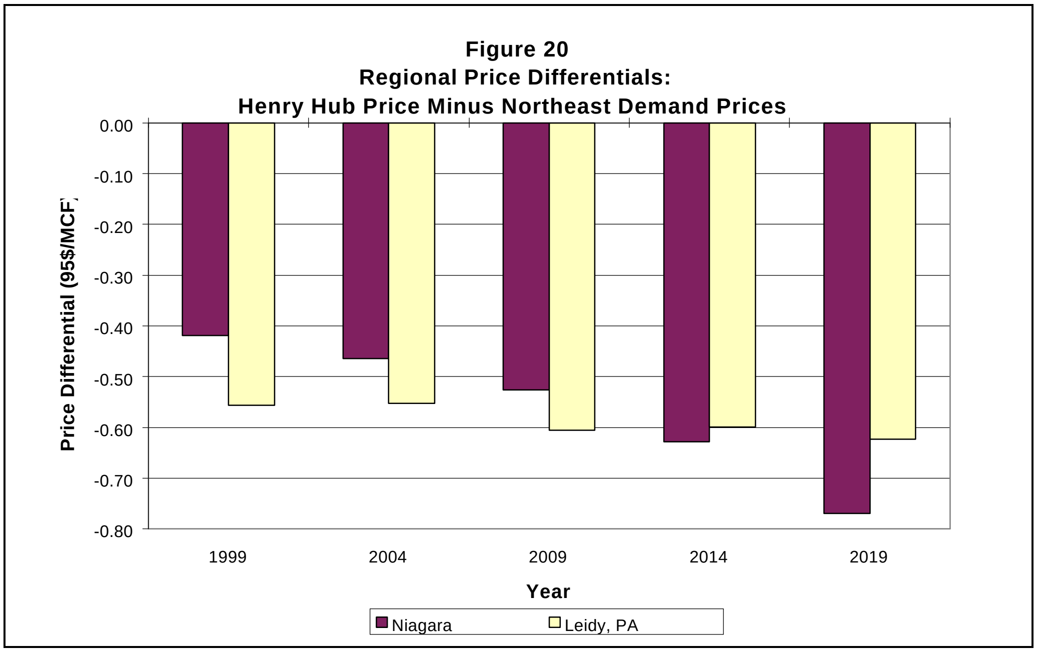

Figure 20
Regional Price Differentials:
Henry Hub Price Minus Northeast Demand Prices

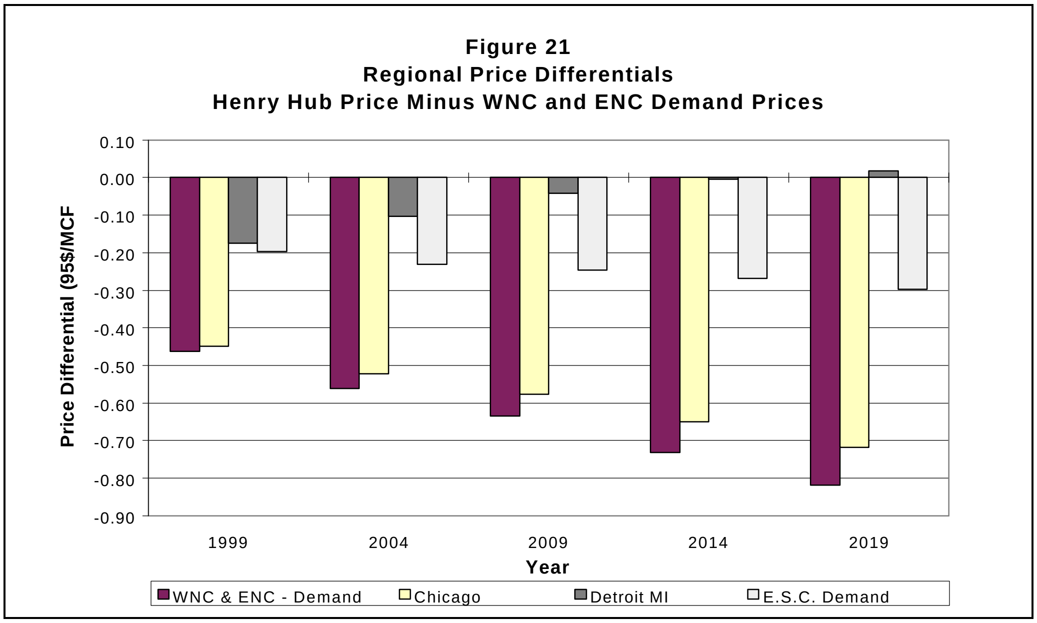

Figure 21
Regional Price Differentials
Henry Hub Price Minus WNC and ENC Demand Prices

Figure 22 compares the Henry Hub prices with prices for the three out-of-state supply sources serving California. Canadian prices at the California border are cheaper than Henry Hub prices through most of the forecast horizon. Canadian prices surpass Henry Hub prices later in the forecast period as demand surges and pipeline capacity utilization rises, lowering any discounts enjoyed by California markets. Southwest and Rocky Mountain prices in the near term are fairly close to Henry Hub prices although they start diverging in later years. This divergence occurs since Henry Hub prices maintain a low growth rate while delivered San Juan and Rocky

Mountain prices at the California border rise at much faster rate (2 percent compared to a Henry Hub growth rate of 1.2 percent).

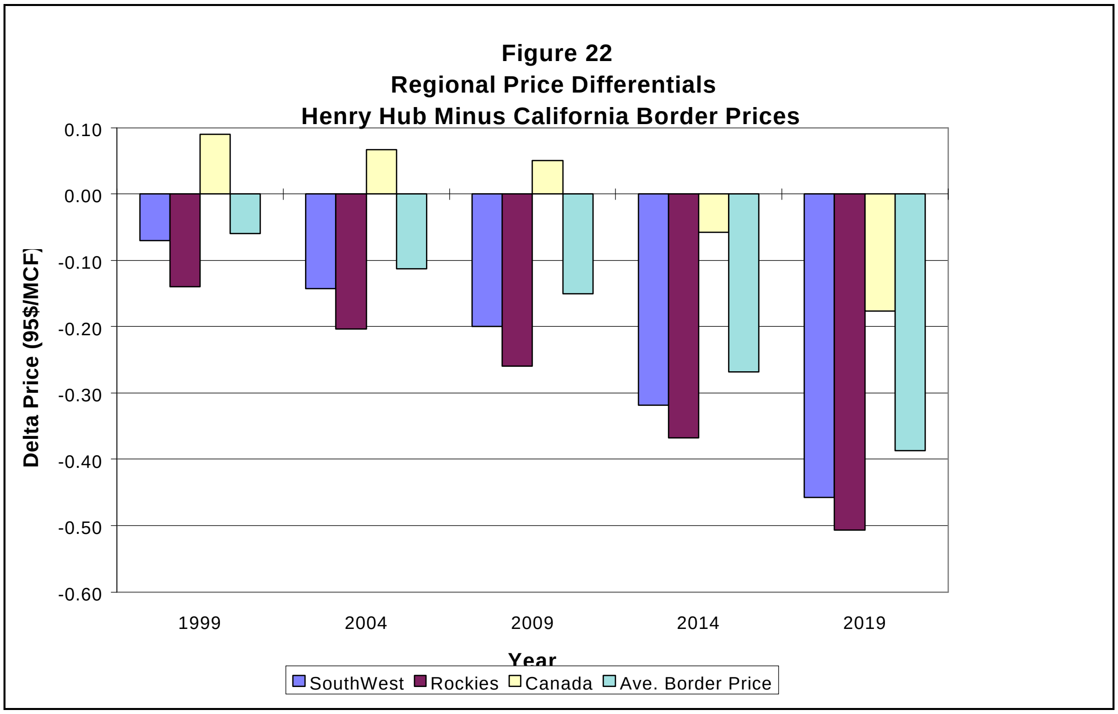

Figure 22
Regional Price Differentials
Henry Hub Minus California Border Prices

APPENDIX A
CEC Resource Cost Curve Definitions

Conventional Resources

Basin	USGS or MMS Province	Description
Anadarko	USGS 53 and 59 USGS 55-56 USGS 58 USGS 60-62	Central Kansas Nehama Uplift Anadarko Basin Arkoma Basin
Appalachian	USGS 67 USGS 68-69	Appalachian Basin Blue Ridge Thrust Belt/Piedmont
California	USGS 7-9 USGS 10-14 Onshore USGS 10-14 Offshore MMS Offshore	Northern California Onshore Southern California Onshore Southern California State Offshore Federal Offshore
Gulf Coast	USGS 47 Onshore USGS 47 Offshore USGS 48-50 Onshore USGS 48-50 Offshore USGS 65 USGS 84 USGS 85 MMS Offshore	Western Gulf Onshore Western Gulf State Offshore Eastern Gulf Onshore Eastern Gulf State Offshore Black Warrior Basin Western Gulf Onshore - High H_2S Content Eastern Gulf Onshore - High H_2S Content Federal Offshore
North Central	USGS 63 USGS 64 and 66	Michigan Basin Illinois Basin & Cincinnati Arch
Northern Great Plains	USGS 27-29 USGS 31 and 51 USGS 33-34 USGS 35	Central/Southwestern Montana Williston Basin Powder River Basin Wind River Basin
Permian	USGS 44 and 46 USGS 45	Permian Basin and Marathon Thrust Belt Fort Worth Basin
Pacific Northwest	USGS 4-5	Oregon - Washington
Rocky Mountains	USGS 17-19 USGS 20 USGS 21 USGS 36 USGS 37 USGS 38-39 USGS 81 USGS 83	Great Basin Uinta-Piceance Basin Paradox Basin Wyoming Thrust Belt Southwestern Wyoming Denver Basin Paradox Basin - High H_2S Content Southwestern Wyoming - High H_2S Content
San Juan	USGS 22-23 USGS 24-25 USGS 40-41	San Juan Basin Arizona-New Mexico Raton Basin

CEC Resource Cost Curve Definitions - Continued

Coalbed Methane

Basin	Plays	Description
Anadarko	USGS 5650 USGS 6050 USGS 6250-6251	Forest City - Central Basin Cherokee Platform - Central Basin Arkoma Basin
Appalachian	USGS 6750-6751 USGS 6752 USGS 6753	Northern Appalachian Central Appalachian Cahaba Field
Gulf Coast	USGS 6550-6553	Black Warrior Basin
North Central	USGS 6450	Illinois - Central Basin
Northern Great Plains	USGS 3350-3351 USGS 3550	Powder River Basin Wind River Basin
Pacific Northwest	USGS 450-452	Western Oregon-Washington
Rocky Mountains	USGS 2050-2052 USGS 2053-2056 USGS 3750-3755	Uinta Basin Piceance Basin Southwestern Wyoming
San Juan	USGS 2250 USGS 2252-2253 USGS 4150-4152	San Juan Overpressured San Juan Underpressured Raton Basin

Tight Gas

Basin	Plays	Description
Appalachian	USGS 6728-6730	Clinton-Medina
Gulf Coast	USGS 4923	Cotton Valley
Northern Great Plains	USGS 2810-2812 USGS 3113	North Central Montana - Biogenic Williston Basin
Rocky Mountains	USGS 2007 USGS 2010 USGS 2015-2020 USGS 3740-3744 USGS 3906	Piceance Basin - Mesaverde Williams Fork Piceance Basin - Mesaverde Iles Uinta Basin Greater Green River Basin Denver Basin
Pacific Northwest	USGS 503	Eastern Oregon-Washington
San Juan	USGS 2205 USGS 2209 USGS 2211	Dakota Central Basin Central Basin Mesaverde Pictured Cliffs

CEC Resource Cost Curve Definitions - Continued

Shale

Basin	USGS Plays	Description
Appalachian	USGS 6733-6735 USGS 6740-6741 USGS 6742	Upper Devonian Sandstone Devonian Shale Devonian Shale - Lower Maturity
North Central	USGS 6319-6320 USGS 6407 USGS 6604	Michigan Basin - Antrim Shale New Albany Cincinnati Arch - Devonian Black Shale
Permian	USGS 4503	Barnett Shale (Fort Worth Basin)

Canadian Cost Curves

Basin	CEC Designation	Description
Alberta	A B C D	Alberta Foothill Region South Central Region Frontier Region Coalbed Methane
British Columbia	A B C	Conventional Sources Coalbed Methane Sources South Territories
Eastern Canada	Offshore	Sable Island Offshore
Northern Canada	Onshore Offshore	Conventional Sources Conventional Sources
Saskatchewan	A	Conventional Sources

RESOURCE COST CURVES - CONVENTIONAL

Anadarko
USGS 53 & 59 - Central Kansas

Proved Reserves 0.000 TCF
R/P Ratio 9.2 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.15	0.69
0.150	0.25	0.86
0.417	0.60	1.44
0.533	2.00	1.45
0.555	2.50	2.00
0.578	3.00	2.50

Anadarko
USGS 55 to 56 - Nehama Uplift

Proved Reserves 0.000 TCF
R/P Ratio 9.2 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.11	0.55
0.182	0.24	0.86
0.290	0.37	1.09
0.395	1.35	1.76
0.434	3.45	2.96

Anadarko
USGS 58 - Anadarko Basin

Proved Reserves 24.105 TCF
R/P Ratio 9.4 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.06	0.39
2.823	0.13	0.53
5.067	0.17	0.61
7.230	0.25	0.84
9.509	0.38	1.01
11.223	0.86	1.38
12.375	1.69	2.28
13.478	3.92	3.05

Anadarko
USGS 60 to 62 - Arkoma Basin

Proved Reserves 3.872 TCF
R/P Ratio 7.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.06	0.39
0.586	0.10	0.58
1.634	0.17	0.62
2.127	0.21	0.85
2.584	0.33	1.02
3.023	0.55	1.19
3.278	0.99	1.75
3.501	1.94	2.78
3.637	3.01	3.19

Appalachia
USGS 67 - Appalachian Basin

Proved Reserves 0.236 TCF
R/P Ratio 35.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.06	0.36
0.332	0.14	0.57
1.248	0.25	0.98
1.726	0.54	1.44
1.890	1.13	2.12
1.974	2.33	3.10

Appalachia
USGS 68 to 69 - Blue Ridge Thrust Belt

Proved Reserves 0.000 TCF
R/P Ratio 35.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.06	0.36
0.222	0.14	0.56
0.337	0.23	0.96
0.405	0.93	1.75
0.411	1.40	2.29
0.415	2.37	3.05

California
USGS 7 to 9 - Northern CA Onshore

Proved Reserves 0.498 TCF
R/P Ratio 5.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.07	0.50
0.112	0.09	0.55
0.418	0.16	0.72
1.185	0.21	0.81
1.756	0.27	0.91
2.595	0.38	1.10
3.044	0.61	1.37
3.436	0.98	1.81
3.631	1.13	1.87
3.860	1.62	1.90
4.045	3.70	1.98
4.102	5.76	2.71

California
USGS 10 to 14 - Southern CA Onshore

Proved Reserves 2.876 TCF
R/P Ratio 11.4 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.08	0.52
0.088	0.10	0.57
0.237	0.14	0.63
0.796	0.21	0.81
1.469	0.30	0.99
2.337	0.51	1.29
3.235	1.13	2.03
3.462	1.76	2.53
3.623	2.70	3.24
3.723	3.04	3.49

California
USGS 10 to 14 - Southern CA Offshore
State Waters

Proved Reserves 0.266 TCF
R/P Ratio 35.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.22	0.64
0.295	0.37	0.64
0.853	0.83	1.20
0.910	0.89	1.26
0.992	0.95	1.38
1.147	2.09	1.89
1.295	4.17	2.60

California
USGS 10 to 14 - Southern CA Offshore
Federal Waters

Proved Reserves 1.471 TCF
R/P Ratio 28.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.22	0.64
2.231	0.37	0.64
6.456	0.83	1.20
6.888	0.89	1.26
7.504	0.95	1.38
8.676	2.09	1.89
9.800	4.17	2.60

Gulf Coast
USGS 47 - Western Gulf Onshore

Proved Reserves 17.542 TCF
R/P Ratio 5.7 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.02	0.34
8.862	0.07	0.43
19.970	0.15	0.56
43.081	0.45	0.58
46.935	0.65	0.69
50.222	1.07	0.77
53.422	1.92	0.81
54.647	2.90	0.91
55.829	5.35	1.30
56.552	9.25	2.67

Gulf Coast
USGS 47 - Western Gulf Offshore
State Waters

Proved Reserves 0.335 TCF
R/P Ratio 4.6 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.18	0.45
0.618	0.30	0.53
2.714	0.53	1.01
4.749	0.92	1.06
5.777	1.23	1.17
6.643	2.09	1.88
6.962	3.40	2.61
7.305	6.13	3.98

Gulf Coast
USGS 48 to 50 - Eastern Gulf Onshore

Proved Reserves 8.778 TCF
R/P Ratio 9.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.02	0.41
5.190	0.16	0.43
9.721	0.31	0.54
13.205	0.66	0.75
14.527	1.08	0.82
15.578	1.62	1.06
17.971	4.59	1.93

Gulf Coast
USGS 48 to 50 - Eastern Gulf Offshore
State Waters

Proved Reserves 0.917 TCF
R/P Ratio 6.4 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.30	0.99
0.182	0.70	1.04
0.488	0.95	1.15
0.586	1.55	1.84
0.653	2.67	3.87

Gulf Coast
USGS 65 - Black Warrior Basin

Proved Reserves 1.732 TCF
R/P Ratio 13.5 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.13	0.57
0.392	0.21	0.70
0.846	0.36	0.93
1.271	0.71	1.39
1.829	2.89	1.57
1.944	3.77	3.33

Gulf Coast
USGS 84 - Western Gulf Onshore
High Sulfur Content

Proved Reserves 0.000 TCF
R/P Ratio 5.7 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.19	0.40
0.559	0.53	0.58
0.838	0.77	0.68
1.175	1.85	0.96
1.266	3.29	1.02
1.367	5.00	3.45

Gulf Coast
USGS 85 - Eastern Gulf Onshore
High Sulfur Content

Proved Reserves 0.000 TCF
R/P Ratio 9.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.05	0.37
0.508	0.16	0.53
1.649	0.30	0.71
2.946	0.64	1.09
3.645	1.03	1.46
3.821	1.57	1.82
4.560	4.26	3.13

Gulf Coast
Federal Waters

Proved Reserves 26.044 TCF
R/P Ratio 5.5 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.18	0.45
8.091	0.30	0.53
35.559	0.53	1.01
62.212	0.92	1.06
75.677	1.23	1.17
87.028	2.09	1.88
91.203	3.40	2.61
95.700	6.13	3.98

North Central
USGS 63 - Michigan Basin

Proved Reserves 0.993 TCF
R/P Ratio 16.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.07	0.64
0.253	0.10	0.76
0.734	0.17	1.01
1.815	0.32	1.40
2.119	0.56	1.78
2.506	1.28	2.67
2.762	5.76	2.97

North Central
USGS 64 & 66 - Illinois Basin

Proved Reserves 0.000 TCF
R/P Ratio 16.9 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.05	0.57
0.078	0.08	0.65
0.204	0.14	0.99
0.339	0.30	1.33
0.389	0.53	1.80
0.423	1.01	2.00
0.436	1.55	2.54
0.485	2.60	3.41

Northern Great Plains
USGS 27 to 29 - Central/SW Montana

Proved Reserves 0.278 TCF
R/P Ratio 13.7 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.06	0.31
0.657	0.09	0.40
1.167	0.15	0.48
1.640	0.25	0.75
2.159	0.33	0.95
2.594	0.51	1.00
2.854	0.90	1.48
3.022	1.79	2.24
3.092	3.36	3.27

Northern Great Plains
USGS 31 & 51 - Williston Basin

Proved Reserves 0.373 TCF
R/P Ratio 13.7 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.05	0.36
0.384	0.37	0.54
0.752	0.72	0.67
1.086	1.14	0.85
1.442	2.98	1.35
1.695	4.70	1.75

Northern Great Plains
USGS 33 to 34 - Powder River Basin

Proved Reserves 0.659 TCF
R/P Ratio 14.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.17	0.73
0.534	0.28	0.80
1.050	0.53	1.04
1.683	1.94	1.12
1.790	2.95	1.43
1.899	4.71	1.91

Northern Great Plains
USGS 35 - Wind River Basin

Proved Reserves 0.839 TCF
R/P Ratio 14.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.11	0.49
0.141	0.24	0.75
0.277	0.42	1.06
0.399	0.64	1.21
0.453	1.65	2.20
0.491	3.27	3.17

Permian
USGS 44 & 46 - Permian Basin

Proved Reserves 14.343 TCF
R/P Ratio 8.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.03	0.34
1.608	0.09	0.42
4.278	0.15	0.49
7.746	0.21	0.60
9.783	0.29	0.74
11.662	0.48	0.98
13.989	1.59	1.00
14.500	2.43	1.30
14.882	3.90	1.75
15.230	4.80	1.76

Permian
USGS 45 - Fort Worth Basin

Proved Reserves 0.000 TCF
R/P Ratio 8.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.10	0.52
0.248	0.14	0.61
0.741	0.18	0.69
1.386	0.24	0.79
1.559	0.60	1.36
1.887	1.33	2.14
1.922	2.34	2.91

Rocky Mountains
USGS 17 to 19 - Great Basin

Proved Reserves 0.000 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.09	0.43
0.099	0.27	1.01
0.206	0.66	1.32
0.254	1.39	1.98
0.291	2.14	2.57
0.308	3.46	3.39
0.332	3.69	3.43

Rocky Mountains
USGS 20 - Uinta/Piceance Basin

Proved Reserves 0.543 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.13	0.72
1.715	0.27	0.98
2.574	0.38	1.16
2.888	0.49	1.25
3.220	0.65	1.58
3.700	1.08	1.89
3.924	1.64	2.27
3.996	3.32	2.30

Rocky Mountains
USGS 21 - Paradox Basin

Proved Reserves 0.336 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.10	0.60
0.220	0.18	0.75
0.589	0.30	0.99
0.949	0.59	1.34
1.222	1.15	1.95
1.329	1.76	2.46
1.472	2.95	3.29

Rocky Mountains
USGS 36 - Wyoming Thrust Belt

Proved Reserves 1.191 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.11	0.51
3.415	0.18	0.60
7.015	0.30	0.77
8.567	0.51	1.02
9.065	0.68	1.24
9.704	2.52	1.30
9.815	3.74	1.63
10.015	5.79	2.11

Rocky Mountains
USGS 37 - Southwestern Wyoming

Proved Reserves 2.805 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.11	0.59
0.071	0.15	0.76
0.236	0.24	0.85
0.300	0.31	0.98
0.468	0.62	1.32
0.526	0.86	1.58
0.582	1.23	1.96
0.629	1.87	2.52
0.708	3.20	3.33

Rocky Mountains
USGS 38 to 39 - Denver Basin

Proved Reserves 0.022 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.05	0.71
0.369	0.10	1.06
0.577	0.22	1.40
0.627	0.38	2.00
0.672	0.85	2.57
0.703	1.25	3.42

Rocky Mountains
USGS 81 - Paradox Basin
High Sulfur Content

Proved Reserves 0.000 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.19	0.67
0.055	0.30	0.87
0.091	0.40	0.98
0.152	0.78	1.51
0.183	1.00	1.71
0.254	3.00	1.91
0.262	5.21	2.00
0.270	8.08	2.57

Rocky Mountains
USGS 83 - Southwestern Wyoming
High Sulfur Content

Proved Reserves 0.000 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.16	0.59
0.147	0.25	0.74
0.244	0.31	0.84
0.358	0.41	0.99
0.480	0.70	1.41
0.562	1.05	1.61
0.643	2.09	2.43
0.753	3.19	3.16

Pacific Northwest
USGS 4 to 5 - Oregon/Washington

Proved Reserves 0.028 TCF
R/P Ratio 8.8 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.10	0.53
0.038	0.13	0.59
0.195	0.25	0.85
0.422	0.37	1.11
0.687	0.83	1.54
0.736	1.13	1.72
0.903	4.31	1.97
1.140	7.68	2.76

San Juan
USGS 22 to 23 - San Juan Basin

Proved Reserves 3.150 TCF
R/P Ratio 35.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.14	0.27
0.205	0.26	0.53
0.520	0.34	0.65
0.796	0.63	1.00
0.975	0.98	1.19
1.078	1.59	1.95
1.131	3.31	2.69
1.179	6.05	3.74

San Juan
USGS 24 to 25 - Arizona/New Mexico

Proved Reserves 0.000 TCF
R/P Ratio 35.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.10	0.36
0.053	0.14	0.42
0.163	0.22	0.57
0.223	0.29	0.70
0.256	0.39	0.84
0.286	0.80	1.27
0.292	1.13	1.57
0.302	1.69	2.09
0.321	4.88	3.81

San Juan
USGS 40 to 41 - Raton Basin

Proved Reserves 0.000 TCF
R/P Ratio 35.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.11	0.53
0.044	0.14	0.55
0.386	0.21	0.74
0.510	0.46	1.11
0.535	1.18	1.98
0.540	2.25	2.90

RESOURCE COST CURVES - COALBED METHANE

Anadarko
USGS 5650 - Forest City (Central Basin)

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	1.18	0.71	0.100	0
0.197	1.44	0.91	0.100	1
0.300	2.28	1.54	0.100	2
0.375	3.00	2.19	0.093	3
0.443	6.00	3.49	0.082	4
			0.071	5
			0.036	10
			0.021	15
			0.014	20
			0.010	24

Anadarko
USGS 6050 - Cherokee Platform (Central Basin)

Proved Reserves 0.070 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.44	0.50	0.063	0
0.636	0.55	0.59	0.063	1
1.100	0.94	0.89	0.063	2
1.400	1.68	1.46	0.063	3
1.600	3.13	2.59	0.063	4
1.890	6.00	4.33	0.063	5
			0.048	10
			0.034	15
			0.026	20
			0.021	24

Anadarko
USGS 6250 to 6251 - Arkoma Basin

Proved Reserves 0.040 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.26	0.60	0.097	0
0.275	0.36	0.82	0.070	1
1.180	0.62	1.37	0.065	2
2.133	1.18	2.39	0.061	3
2.675	3.41	3.78	0.057	4
			0.053	5
			0.039	10
			0.029	15
			0.023	20
			0.020	24

Appalachia
USGS 6750 to 6751 - Northern Appalachia

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.30	0.61	0.071	0
1.643	0.42	0.96	0.071	1
8.686	0.96	1.04	0.071	2
10.831	1.78	1.87	0.071	3
11.710	3.79	4.84	0.071	4
			0.067	5
			0.044	10
			0.020	20
			0.016	24

Appalachia
USGS 6752 - Central Appalachia

Proved Reserves 0.810 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.26	0.34	0.196	0
0.549	0.34	0.41	0.143	1
1.777	0.51	0.61	0.098	2
2.190	2.00	1.02	0.074	3
2.309	3.87	2.48	0.059	4
			0.049	5
			0.026	10
			0.017	15
			0.013	20
			0.010	24

Appalachia
USGS 6753 - Cahaba Field

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.53	0.35	0.045	0
0.133	0.71	0.49	0.045	1
0.179	1.09	0.79	0.045	2
0.249	1.84	1.37	0.045	3
0.274	3.31	2.50	0.045	4
0.290	6.17	4.29	0.045	5
			0.045	6
			0.049	7
			0.049	9
			0.048	10
			0.041	15
			0.034	20
			0.030	24

Gulf Coast
USGS 6550 to 6553 - Black Warrior Basin

Proved Reserves 1.237 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.44	0.56	0.098	0
0.090	0.54	0.68	0.098	1
1.276	0.83	0.71	0.098	2
2.015	1.44	1.41	0.098	3
2.226	3.28	2.57	0.082	4
2.308	5.97	3.52	0.069	5
			0.058	6
			0.050	7
			0.044	8
			0.038	9
			0.034	10
			0.021	15
			0.014	20
			0.011	24

North Central
USGS 6450 - Illinois-Central Basin

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.75	1.02	0.061	0
0.800	1.16	1.44	0.087	1
1.200	2.14	2.36	0.096	2
1.611	6.00	5.22	0.092	3
			0.083	4
			0.072	5
			0.036	10
			0.015	20
			0.011	24

Northern Great Plains
USGS 3350 to 3351 - Powder River Basin

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.25	0.35	0.320	0
0.295	0.39	0.43	0.255	1
0.349	0.66	0.59	0.135	2
0.914	1.19	0.91	0.080	3
1.349	2.24	1.54	0.051	4
1.475	4.32	2.71	0.035	5
			0.009	10
			0.004	15
			0.002	20
			0.001	24

Northern Great Plains USGS 3550 - Wind River Basin Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.25	0.35	0.081	0
0.211	0.33	0.38	0.081	1
0.336	1.19	0.91	0.081	2
0.375	2.71	2.05	0.081	3
0.429	4.32	2.71	0.073	4
			0.065	5
			0.038	10
			0.025	15
			0.017	20
			0.013	24

Pacific Northwest USGS 450 to 452 - Western Oregon/Washington Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.47	0.35	0.061	0
0.203	0.52	0.38	0.043	1
0.463	1.23	0.57	0.040	2
0.489	1.42	0.90	0.036	3
0.590	2.12	1.00	0.034	4
0.675	3.76	1.61	0.034	5
0.698	5.51	2.62	0.040	10
			0.041	15
			0.040	20
			0.039	24

Rocky Mountains
USGS 2050 to 2052 - Uinta Basin

Proved Reserves 0.240 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.20	0.46	0.061	0
1.724	0.34	0.51	0.061	1
3.442	0.62	0.70	0.061	2
3.509	0.72	0.83	0.061	3
3.720	1.03	0.91	0.061	4
4.353	1.48	1.28	0.061	5
4.794	2.61	2.18	0.060	6
4.908	5.14	3.95	0.058	7
			0.055	8
			0.052	9
			0.049	10
			0.043	12
			0.036	15
			0.028	20
			0.027	21
			0.026	22
			0.025	23
			0.023	24

Rocky Mountains
USGS 2053 to 2056 - Piceance Basin

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.18	0.43	0.061	0
2.261	0.23	0.46	0.050	1
4.696	0.38	0.50	0.052	2
6.191	0.56	0.61	0.054	3
6.404	0.69	0.70	0.053	4
6.863	0.96	0.85	0.052	5
7.200	1.22	0.96	0.050	6
7.602	5.28	3.82	0.048	7
			0.046	8
			0.044	9
			0.042	10
			0.034	15
			0.029	20
			0.026	24

Rocky Mountains
USGS 3750 to 3755- Southwestern Wyoming

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.16	0.42	0.048	0
0.272	0.20	0.44	0.048	1
0.744	0.26	0.49	0.048	2
1.576	0.50	0.58	0.048	3
1.738	0.56	0.65	0.048	4
2.223	0.73	0.79	0.048	5
2.997	1.28	0.94	0.044	14
3.376	2.12	1.23	0.034	15
3.676	2.71	2.10	0.024	17
3.839	5.24	3.83	0.020	20
			0.017	24

San Juan
USGS 2250 - San Juan Basin Overpressured

Proved Reserves 3.910 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.06	0.21	0.079	0
7.056	0.29	0.35	0.079	1
8.541	0.55	0.52	0.079	2
11.141	1.08	0.84	0.079	3
12.997	2.10	1.46	0.079	4
15.292	4.13	2.69	0.079	5
			0.069	6
			0.062	7
			0.056	8
			0.052	9
			0.048	10
			0.035	15
			0.028	20
			0.024	24

San Juan
USGS 2252 to 2253 - San Juan Basin Underpressured

Proved Reserves 3.910 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.17	0.24	0.084	0
6.187	0.26	0.30	0.084	1
7.791	0.46	0.42	0.084	2
10.212	1.59	1.11	0.084	3
11.141	3.07	1.93	0.073	4
12.607	5.27	3.22	0.065	5
			0.038	10
			0.025	15
			0.017	20
			0.013	24

San Juan
USGS 4150 to 4152 - Raton Basin

Proved Reserves 0.810 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.07	0.23	0.074	0
0.044	0.09	0.25	0.074	1
0.832	0.17	0.30	0.074	2
1.384	0.31	0.42	0.074	3
1.510	1.15	1.03	0.068	4
1.600	2.00	1.39	0.060	5
1.700	2.24	1.84	0.037	10
1.804	4.38	3.15	0.022	20
			0.019	24

RESOURCE COST CURVES - TIGHT SANDS

Appalachia
USGS 6728 to 6730 - Clinton/Medina

Proved Reserves 4.580 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.52	1.16	0.209	0
1.326	0.71	1.26	0.159	1
3.556	0.89	1.38	0.124	2
7.402	1.16	1.50	0.098	3
14.229	1.91	1.77	0.079	4
20.987	3.60	2.50	0.064	5
27.145	4.34	2.97	0.053	6
			0.045	7
			0.038	8
			0.032	9
			0.028	10
			0.024	11
			0.021	12
			0.018	13

Gulf Coast
USGS 4923 - Cotton Valley

Proved Reserves 2.978 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.05	0.35	0.144	0
0.982	0.07	0.36	0.119	1
2.838	0.11	0.38	0.100	2
4.000	0.52	0.78	0.084	3
5.100	2.10	1.62	0.072	4
5.770	6.36	2.42	0.061	5
			0.030	6
			0.016	15
			0.009	20
			0.006	25
			0.005	27

Northern Great Plains
USGS 2810 to 2812 - North Central Montana

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.08	0.41	0.076	0
2.375	0.13	0.50	0.069	1
8.756	0.22	0.74	0.063	2
13.877	0.41	1.12	0.058	3
25.559	0.80	1.22	0.053	4
32.746	0.99	1.35	0.049	5
37.524	1.35	1.65	0.033	10
41.177	2.29	1.94	0.023	15
42.754	4.22	3.52	0.015	20
			0.009	30
			0.007	35
			0.005	44

Northern Great Plains
USGS 3113 - Williston Basin

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	1.67	1.16	0.083	0
1.043	1.90	1.80	0.075	1
1.532	2.57	2.80	0.068	2
1.732	3.75	3.25	0.062	3
1.789	6.59	3.52	0.057	4
			0.053	5
			0.049	6
			0.045	7
			0.042	8
			0.039	9
			0.037	10
			0.027	15
			0.021	20
			0.016	26

Pacific Northwest
USGS 503 - Eastern Oregon/Washington

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	1.91	0.47	0.220	0
1.648	2.17	0.49	0.172	1
5.138	4.11	0.65	0.134	2
8.232	4.64	0.69	0.104	3
9.132	5.98	0.73	0.081	4
12.091	7.08	0.82	0.063	5
			0.049	6
			0.038	7
			0.030	8
			0.023	9
			0.018	10
			0.005	15
			0.004	16
			0.002	19

Rocky Mountains
USGS 2007 - Piceance Basin (Mesaverde Williams Fork)

Proved Reserves 0.994 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.61	0.73	0.220	0
1.287	0.73	0.79	0.171	1
3.700	1.14	0.85	0.133	2
4.000	1.95	1.16	0.104	3
4.300	3.64	1.62	0.081	4
4.774	6.93	2.00	0.063	5
			0.049	6
			0.038	7
			0.030	8
			0.023	9
			0.018	10
			0.014	11
			0.011	12
			0.009	13
			0.007	14
			0.005	15
			0.004	16
			0.003	17
			0.002	20

Rocky Mountains
USGS 2010 - Piceance Basin (Mesaverde Iles)

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.66	0.71	0.220	0
1.131	0.78	0.77	0.171	1
3.845	1.21	0.88	0.133	2
4.100	2.06	1.16	0.104	3
4.400	3.80	1.62	0.081	4
4.722	7.24	3.55	0.063	5
			0.049	6
			0.038	7
			0.030	8
			0.023	9
			0.018	10
			0.014	11
			0.011	12
			0.009	13
			0.007	14
			0.005	15
			0.004	16
			0.003	17
			0.002	20

Rocky Mountains
USGS 2015 to 2020 - Uinta Basin

Proved Reserves 0.434 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.08	0.49	0.120	0
0.246	0.11	0.56	0.106	1
0.291	0.13	0.58	0.093	2
0.607	0.18	0.61	0.082	3
0.965	0.21	0.76	0.072	4
1.506	0.36	0.80	0.064	5
2.022	0.60	1.05	0.056	6
2.228	0.79	1.08	0.050	7
2.847	1.14	1.11	0.044	8
2.920	1.17	1.27	0.039	9
3.298	1.59	1.75	0.030	11
3.505	1.79	1.75	0.018	15
5.050	2.74	1.75	0.010	20
5.920	4.86	3.21	0.005	25
6.803	7.36	3.32	0.002	34

Rocky Mountains
USGS 3740 to 3744 - Greater Green River Basin

Proved Reserves 6.162 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.21	0.42	0.217	0
1.059	0.24	0.44	0.170	1
1.134	0.31	0.52	0.133	2
3.161	0.46	0.67	0.104	3
11.716	0.64	0.69	0.081	4
15.043	0.74	0.77	0.064	5
27.759	1.00	0.80	0.050	6
35.006	1.11	1.01	0.039	7
40.459	1.41	1.06	0.031	8
53.262	1.65	1.12	0.024	9
74.129	2.46	1.15	0.019	10
91.876	3.00	1.46	0.015	11
99.912	4.05	1.68	0.011	12
107.616	5.39	1.89	0.009	13
117.140	8.49	2.81	0.007	14
			0.006	15
			0.004	16
			0.003	18
			0.002	20

Rocky Mountains
USGS 3906 - Denver Basin

Proved Reserves 2.301 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.28	1.03	0.123	0
0.512	0.40	1.51	0.103	1
0.726	0.68	2.35	0.087	2
0.796	1.24	2.97	0.075	3
0.815	4.86	5.98	0.064	5
			0.033	10
			0.019	15
			0.008	25
			0.002	43

San Juan
USGS 2205 - Dakota Central Basin

Proved Reserves 2.105 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.27	0.30	0.091	0
4.838	0.38	0.43	0.083	1
6.800	0.57	0.69	0.075	2
7.576	1.78	1.78	0.069	3
8.281	6.56	3.12	0.057	5
			0.036	10
			0.014	20
			0.009	25
			0.005	30
			0.003	35
			0.002	40

San Juan
USGS 2209 - Central Basin Mesaverde

Proved Reserves 4.592 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.07	0.20	0.074	0
3.016	0.25	0.22	0.069	1
4.511	0.50	0.25	0.064	2
6.858	1.00	0.32	0.059	3
8.287	1.50	0.48	0.051	5
9.160	2.00	1.22	0.035	10
9.327	3.01	2.37	0.016	20
			0.011	25
			0.008	30
			0.005	35
			0.004	49

San Juan
USGS 2211 - Pictured Cliffs

Proved Reserves 0.963 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.22	0.26	0.097	0
0.875	0.40	0.30	0.088	1
2.132	0.75	0.44	0.080	2
2.718	1.00	0.70	0.072	3
2.917	2.25	0.96	0.065	5
3.129	4.87	3.02	0.059	10
			0.023	20
			0.014	25
			0.009	30
			0.005	35

RESOURCE COST CURVES - SHALE

Appalachia
USGS 6733 to 6735 - Upper Devonian Sandstone

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.97	1.70	0.407	0
2.740	1.48	1.99	0.211	1
5.172	2.40	2.07	0.125	2
7.373	3.82	2.56	0.082	3
10.378	5.87	2.60	0.057	4
12.781	7.68	2.75	0.041	5
			0.031	8

Appalachia
USGS 6740 to 6741 - Devonian Shale

Proved Reserves 1.380 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.14	0.59	0.052	0
0.880	0.19	0.70	0.049	1
3.981	0.21	0.85	0.046	2
6.293	0.55	1.88	0.043	3
7.748	1.54	2.24	0.040	4
8.900	2.32	3.71	0.038	5
9.785	4.52	5.71	0.029	10
			0.023	15
			0.019	20
			0.015	25
			0.013	30
			0.011	35
			0.010	40
			0.008	45
			0.008	49

Appalachia
USGS 6742 - Devonian Shale (Lower Maturity)

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.71	1.58	0.097	0
1.690	1.02	2.78	0.085	1
2.716	1.97	3.48	0.075	2
3.310	5.21	5.32	0.066	3
			0.059	4
			0.054	5
			0.034	10
			0.024	15
			0.018	20
			0.014	25
			0.013	27

North Central
USGS 6319 to 6320 - Michigan Basin (Antrim Shale)

Proved Reserves 1.010 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.15	0.74	0.107	0
1.244	0.15	0.86	0.093	1
6.048	0.29	1.29	0.081	2
11.495	0.61	1.67	0.071	3
14.580	1.23	1.74	0.063	4
15.839	2.39	2.12	0.055	5
16.215	5.64	3.19	0.032	10
			0.020	15
			0.014	20
			0.010	25
			0.007	30
			0.006	34

North Central
USGS 6407 - New Albany

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.87	1.17	0.082	0
0.408	1.01	1.71	0.075	1
0.904	1.70	2.21	0.069	2
1.392	2.22	3.96	0.063	3
1.772	6.69	6.16	0.058	4
			0.054	5
			0.038	10
			0.027	15
			0.021	20
			0.015	26

North Central
USGS 6604 - Cincinnati Arch (Devonian Black Shale)

Proved Reserves 0.000 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	1.55	1.01	0.081	0
0.301	1.66	1.43	0.074	1
0.626	1.93	2.43	0.068	2
1.033	2.56	3.36	0.062	3
1.254	3.72	3.85	0.057	4
1.306	6.08	4.90	0.053	5
			0.053	10
			0.037	15
			0.027	20
			0.016	25
			0.014	27

Permian
USGS 4503 - Barnett Shale (Fort Worth Basin)

Proved Reserves 0.012 TCF

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)	Production Profile	Production Year
0.000	0.27	0.48	0.291	0
0.473	0.38	0.51	0.206	1
1.342	0.45	0.56	0.146	2
1.438	0.62	0.61	0.103	3
2.370	0.83	0.69	0.073	4
2.473	1.12	0.74	0.052	5
2.981	1.58	0.84	0.037	6
3.037	2.13	0.91	0.026	7
3.266	4.14	1.19	0.018	8
			0.013	9
			0.009	10
			0.007	11
			0.005	12
			0.003	13

RESOURCE COST CURVES - CANADA

Alberta - A
Foothills
Conventional

Proved Reserves 25.840 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.05	0.46
3.062	0.07	0.47
6.233	0.11	0.49
10.963	0.17	0.51
15.217	0.17	0.54
17.087	0.17	0.56
20.112	0.17	0.59
26.052	0.17	0.59
31.827	0.17	0.60
35.567	0.17	0.68
38.518	0.17	0.78
42.643	0.23	0.78
48.290	0.31	0.78
54.377	0.58	0.78
59.125	0.68	0.78
62.718	1.68	0.78
65.945	1.86	2.00
73.333	3.78	4.01

Alberta - B
South Central
Conventional

Proved Reserves 23.000 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.04	0.36
1.558	0.09	0.36
4.125	0.09	0.36
9.772	0.09	0.37
12.467	0.12	0.40
14.740	0.12	0.43
19.873	0.12	0.43
22.495	0.15	0.45
24.310	0.15	0.45
29.590	0.22	0.45
31.295	0.24	0.45
33.110	0.25	0.50
35.072	0.42	0.51
37.693	0.45	0.52
41.433	0.50	0.59
46.933	1.39	1.46
49.500	2.36	2.02
56.833	4.21	4.03

Alberta - C
Frontier
Conventional

Proved Reserves 4.006 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.06	0.34
0.458	0.10	0.37
1.412	0.14	0.46
2.713	0.23	0.46
3.245	0.28	0.46
4.363	0.29	0.53
5.610	0.31	0.56
6.527	0.49	0.56
7.737	0.50	0.60
8.855	0.57	0.60
11.532	1.05	0.60
12.723	1.22	0.68
13.768	1.22	1.08
15.730	2.25	1.27
16.757	2.25	1.67
17.655	2.25	1.74
18.718	3.79	3.99
20.643	5.24	5.78
23.833	9.15	7.62

Alberta - D
Coalbed Methane

Proved Reserves 0.000 TCF
R/P Ratio 20.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.18	0.30
2.369	0.18	0.38
13.965	0.23	0.41
14.968	0.30	0.41
22.662	0.42	0.47
27.000	0.78	0.62
31.000	1.05	0.68
34.000	2.61	0.81
38.000	4.18	1.29
41.000	6.27	4.18

British Columbia - A
Conventional

Proved Reserves 8.520 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.02	0.48
0.970	0.02	0.48
2.480	0.03	0.48
4.620	0.04	0.49
8.340	0.09	0.50
8.940	0.19	0.55
11.530	0.28	0.56
13.200	0.47	0.58
16.030	0.57	0.61
19.790	0.71	0.66
22.530	0.85	0.71
27.860	0.99	0.73
29.870	1.18	0.78
31.510	1.42	0.84
32.930	1.89	0.84
33.740	2.36	1.20
34.150	2.83	1.65
35.000	3.31	2.03
36.000	3.78	3.58

British Columbia - B
Coalbed Methane

Proved Reserves 2.000 TCF
R/P Ratio 20.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	1.13	0.47
2.000	1.32	0.55
4.000	1.70	0.78
6.000	1.98	1.06
7.000	2.36	1.65
8.000	3.78	2.24
8.500	4.72	2.83
9.000	5.67	3.22

British Columbia - C
South Territories

Proved Reserves 0.000 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.52	0.26
0.139	0.52	0.26
0.223	0.56	0.26
0.667	0.60	0.28
0.742	0.65	0.34
0.868	0.77	0.34
1.302	1.29	0.39
1.551	2.15	0.43
2.074	2.37	0.52
2.210	2.67	0.60
2.390	3.01	0.65
2.608	3.66	0.77
2.706	4.21	0.86
2.936	4.99	1.03
3.155	5.59	1.51

Eastern Canada
Sable Island (Offshore)

Proved Reserves 5.000 TCF
R/P Ratio 20.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.52	0.34
2.360	0.60	0.34
2.930	0.69	0.34
4.000	0.86	0.52
6.000	1.29	0.56
8.200	2.15	1.29
12.780	3.44	3.44

Northern Canada
Offshore - Conventional

Proved Reserves 0.000 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	1.322	0.525
8.000	1.463	0.567
15.000	1.917	0.567
20.000	4.722	3.778

Northern Canada
Onshore - Conventional

Proved Reserves 12.785 TCF
R/P Ratio 20.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.944	0.839
10.000	1.889	1.036
15.000	2.833	1.232
20.000	3.541	1.429
25.000	4.250	1.626
30.000	4.958	2.020
35.000	5.667	2.414
40.000	6.374	3.200

Saskatchewan
Conventional

Proved Reserves 3.079 TCF
R/P Ratio 10.0 Years

Cumulative Reserves (TCF)	Capital Cost (95$/MCF)	Operating Cost (95$/MCF)
0.000	0.019	0.387
0.300	0.019	0.387
0.690	0.236	0.448
1.030	0.614	0.645
1.550	0.944	0.841
1.760	1.416	1.236
2.080	2.125	1.629
2.230	2.833	2.023
2.800	3.778	2.416
3.800	5.667	2.810

APPENDIX B
Adjusted Drilling Cost Impacts for Gas Wells

		Unadjusted Percent Drilling Cost	**Drilling Cost Reduction Factors**				Adjusted Percent Drilling Cost	Percent Development Cost	Adjusted Total Capital Cost	Future Technology Factor	Adjusted Total Capital Cost
			3-D Seismic	Horizontal Drilling	Slim Hole Drilling	New Bits					
Appalachia	Conventional	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
	Coalbed	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
	Tight Sands	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
	Shale	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
Anadarko	Conventional	34.5%	0.940	1.000	0.986	0.700	22.4%	65.5%	87.9%	20.0%	67.9%
	Coalbed	34.5%	0.940	1.000	0.986	0.700	22.4%	65.5%	87.9%	20.0%	67.9%
Arkoma	Conventional	48.0%	0.940	1.000	0.986	0.700	31.1%	52.0%	83.1%	20.0%	63.1%
California	North	55.2%	0.940	1.000	0.986	0.700	35.8%	44.8%	80.6%	20.0%	60.6%
	South	55.2%	0.940	1.000	0.986	0.700	35.8%	44.8%	80.6%	20.0%	60.6%
	Offshore	55.2%	0.940	1.000	0.986	0.700	35.8%	44.8%	80.6%	20.0%	60.6%
Gulf Onshore	Eastern Gulf	33.7%	0.940	1.000	0.986	0.700	21.9%	66.3%	88.1%	20.0%	68.1%
	Western Gulf	44.5%	0.940	1.000	0.986	0.700	28.8%	55.5%	84.4%	20.0%	64.4%
	Black Warrior	90.0%	0.940	1.000	0.986	0.700	58.4%	10.0%	68.4%	20.0%	48.4%
	Coalbed	33.7%	0.940	1.000	0.986	0.700	21.9%	66.3%	88.1%	20.0%	68.1%
	Tight Sands	33.7%	0.940	1.000	0.986	0.700	21.9%	66.3%	88.1%	20.0%	68.1%
Gulf Offshore	Conventional	90.0%	0.940	1.000	0.986	0.700	58.4%	10.0%	68.4%	20.0%	48.4%
North Central	Conventional	74.4%	0.940	1.000	0.986	0.700	48.3%	25.6%	73.9%	20.0%	53.9%
	Shale	74.4%	0.940	1.000	0.986	0.700	48.3%	25.6%	73.9%	20.0%	53.9%
	Coalbed	74.4%	0.940	1.000	0.986	0.700	48.3%	25.6%	73.9%	20.0%	53.9%
Northern Great Plains	Conventional	66.7%	0.940	1.000	0.986	0.700	43.2%	33.3%	76.6%	20.0%	56.6%
	Coalbed	66.7%	0.940	1.000	0.986	0.700	43.2%	33.3%	76.6%	20.0%	56.6%
	Tight	66.7%	0.940	1.000	0.986	0.700	43.2%	33.3%	76.6%	20.0%	56.6%
Pacific Northwest	Conventional	56.7%	0.940	1.000	0.986	0.700	36.8%	43.3%	80.1%	20.0%	60.1%
	Coalbed	56.7%	0.940	1.000	0.986	0.700	36.8%	43.3%	80.1%	20.0%	60.1%
Permian	Conventional	57.3%	0.940	1.000	0.986	0.700	37.2%	42.7%	79.9%	20.0%	59.9%
Rocky Mountains	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Coalbed	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Tight Sands	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
San Juan Basin	Conventional	48.0%	0.940	1.000	0.986	0.700	31.1%	52.0%	83.2%	20.0%	63.2%
	Coalbed	48.0%	0.969	1.000	0.986	0.700	32.1%	52.0%	84.1%	20.0%	64.1%
	Tight Sands	48.0%	0.940	1.000	0.986	0.700	31.1%	52.0%	83.2%	20.0%	63.2%
British Columbia	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Coalbed	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
Alberta	Foothills	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	South Central	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Frontier	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Coalbed	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
Saskatchewan	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
East Canada	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
North Canada	Onshore	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Offshore	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%

Notes: 1) Canadian factors based on corresponding resource types in the Rocky Mountains.
2) Drilling cost reduction factors derived based on review of technology-related literature.
3) Pacific Northwest factors based on average for the Lower 48.

APPENDIX C
NATURAL GAS DEMAND PROJECTIONS

Core Demand by NARG Region - TCF per Year									
NARG Region	1999	2004	2009	2014	2019	2024	2029	2034	2039
Lower 48									
East North Central	2.9590	3.0348	3.1067	3.1835	3.2481	3.2717	3.2797	3.2827	3.2839
East South Central	0.6181	0.6693	0.7152	0.7596	0.7993	0.8145	0.8199	0.8221	0.8231
Middle Atlantic	1.6476	1.6691	1.7052	1.7483	1.7789	1.7895	1.7932	1.7948	1.7955
New England	0.4350	0.4640	0.4975	0.5284	0.5552	0.5654	0.5689	0.5702	0.5708
Pacific Northwest	0.2528	0.2713	0.2899	0.3058	0.3200	0.3254	0.3274	0.3281	0.3284
Rocky Mountains	0.4414	0.4677	0.4916	0.5137	0.5333	0.5407	0.5432	0.5441	0.5445
South Atlantic	1.1277	1.2368	1.3562	1.4766	1.5827	1.6229	1.6367	1.6415	1.6434
Southwest Desert	0.1791	0.1938	0.2073	0.2193	0.2300	0.2342	0.2358	0.2366	0.2371
West North Central	1.0015	1.0371	1.0731	1.1069	1.1358	1.1465	1.1502	1.1517	1.1524
West South Central	2.1809	2.3374	2.4652	2.5753	2.6814	2.7224	2.7364	2.7414	2.7436
California									
PG&E	0.2620	0.2730	0.2830	0.2970	0.3110	0.3150	0.3190	0.3220	0.3260
SoCalGas	0.4040	0.4330	0.4590	0.4830	0.5070	0.5130	0.5190	0.5250	0.5280
SDG&E	0.0590	0.0650	0.0700	0.0750	0.0790	0.0800	0.0810	0.0820	0.0840
Non-Utility									
Northern California	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Southern California	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
EOR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Canada									
British Columbia	0.1390	0.1559	0.1736	0.1919	0.2119	0.2140	0.2161	0.2183	0.2205
Eastern Canada	0.2027	0.2198	0.2356	0.2583	0.2850	0.2878	0.2907	0.2936	0.2965
Ontario	0.7901	0.8490	0.8977	0.9486	1.0038	1.0138	1.0240	1.0342	1.0445
Western Canada	0.8131	0.8966	0.9415	1.0210	1.1219	1.1331	1.1444	1.1559	1.1674
Mexico									
Baja	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
North	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
East	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total									
Lower 48 (No CA)	10.8431	11.3814	11.9078	12.4174	12.8647	13.0331	13.0914	13.1131	13.1226
California	0.7250	0.7710	0.8120	0.8550	0.8970	0.9080	0.9190	0.9290	0.9380
Canada	1.9449	2.1212	2.2484	2.4198	2.6225	2.6487	2.6752	2.7019	2.7290
Mexico	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Source:		
	Lower 48 (Except California) -	GRI Baseline Projection Databook (1996)
	California -	1996 Electricity Report
	Canada -	Canadian Gas Association
	Mexico -	Energy Information Administration

Notes:
1) Data after 2010 are extrapolations.
2) Noncore demand includes oil consumption on a gas equivalent basis of noncore facilities with fuel switching capability.
3) California non-utility demand is only natural gas.

Noncore Demand by NARG Region - TCF per Year

NARG Region	1999	2004	2009	2014	2019	2024	2029	2034	2039
Lower 48									
East North Central	0.9321	1.0866	1.2064	1.4615	1.6216	1.7733	1.8010	1.8959	1.9005
East South Central	0.4022	0.4705	0.5094	0.6260	0.6887	0.7559	0.7675	0.8150	0.8174
Middle Atlantic	1.1846	1.4087	1.7019	1.8934	2.0995	2.2603	2.3100	2.3705	2.3793
New England	0.5196	0.6002	0.6756	0.7157	0.7562	0.8008	0.8170	0.8349	0.8386
Pacific Northwest	0.1740	0.2136	0.2441	0.2823	0.3040	0.3321	0.3361	0.3561	0.3568
Rocky Mountains	0.1637	0.2006	0.2458	0.3229	0.3700	0.4254	0.4355	0.4728	0.4746
South Atlantic	1.1266	1.3124	1.5402	1.7233	1.8863	2.0217	2.0615	2.1204	2.1280
Southwest Desert	0.1457	0.1826	0.1966	0.1958	0.1979	0.2094	0.2109	0.2202	0.2206
West North Central	0.3611	0.4638	0.6143	0.8936	1.1497	1.3424	1.3936	1.4774	1.4847
West South Central	3.5097	3.9200	4.0268	4.2133	4.2720	4.4936	4.5093	4.7042	4.7074
California									
PG&E	0.4740	0.5140	0.5850	0.6250	0.6650	0.6750	0.6850	0.6950	0.7050
SoCalGas	0.4210	0.5040	0.5450	0.6010	0.6300	0.6440	0.6520	0.6610	0.6690
SDG&E	0.0600	0.0920	0.1030	0.1220	0.1310	0.1360	0.1410	0.1460	0.1510
Non-Utility									
Northern California	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200
Southern California	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180
EOR	0.2880	0.2870	0.2840	0.2780	0.2760	0.2750	0.2750	0.2750	0.2740
Canada									
British Columbia	0.0771	0.0943	0.0975	0.1000	0.1033	0.1043	0.1054	0.1064	0.1075
Eastern Canada	0.1123	0.1215	0.1343	0.1561	0.1959	0.1979	0.1999	0.2019	0.2039
Ontario	0.2643	0.2817	0.2990	0.3295	0.3707	0.3745	0.3782	0.3820	0.3858
Western Canada	0.2563	0.3179	0.3621	0.4467	0.5732	0.5789	0.5847	0.5906	0.5965
Mexico									
Baja	0.0050	0.1370	0.1430	0.1500	0.1570	0.1570	0.1570	0.1570	0.1570
North	0.0820	0.0870	0.0910	0.0960	0.0810	0.0810	0.0810	0.0810	0.0810
East	0.0620	0.1390	0.1460	0.1540	0.1290	0.1290	0.1290	0.1290	0.1290
Total									
Lower 48 (No CA)	8.5193	9.8589	10.9611	12.3278	13.3458	14.4150	14.6424	15.2675	15.3080
California	1.2810	1.4350	1.5550	1.6640	1.7400	1.7680	1.7910	1.8150	1.8370
Canada	0.7100	0.8154	0.8928	1.0323	1.2432	1.2556	1.2682	1.2808	1.2937
Mexico	0.1500	0.3630	0.3810	0.3990	0.3670	0.3670	0.3670	0.3670	0.3670

Source:		
	Lower 48 (Except California) -	GRI Baseline Projection Databook (1996)
	California -	1996 Electricity Report
	Canada -	Canadian Gas Association
	Mexico -	Energy Information Administration

Notes:
1) Data after 2010 are extrapolations.
2) Noncore demand includes oil consumption on a gas equivalent basis of noncore facilities with fuel switching capability.
3) California non-utility demand is only natural gas.

Total Demand by NARG Region - TCF per Year

NARG Region	1999	2004	2009	2014	2019	2024	2029	2034	2039
Lower 48									
East North Central	3.8911	4.1211	4.3131	4.6449	4.8698	5.0450	5.0808	5.1786	5.1844
East South Central	1.0203	1.1398	1.2246	1.3856	1.4879	1.5704	1.5875	1.6370	1.6405
Middle Atlantic	2.8322	3.0778	3.4071	3.6417	3.8784	4.0498	4.1032	4.1652	4.1748
New England	0.9546	1.0642	1.1731	1.2441	1.3114	1.3662	1.3859	1.4051	1.4094
Pacific Northwest	0.4268	0.4849	0.5340	0.5881	0.6239	0.6575	0.6635	0.6842	0.6853
Rocky Mountains	0.6052	0.6685	0.7376	0.8368	0.9035	0.9664	0.9790	1.0172	1.0195
South Atlantic	2.2543	2.5492	2.8964	3.1999	3.4690	3.6447	3.6982	3.7619	3.7714
Southwest Desert	0.3248	0.3763	0.4038	0.4151	0.4279	0.4436	0.4468	0.4569	0.4577
West North Central	1.3626	1.5009	1.6874	2.0006	2.2854	2.4888	2.5438	2.6290	2.6371
West South Central	5.6906	6.2573	6.4920	6.7887	6.9534	7.2160	7.2457	7.4457	7.4510
California									
PG&E	0.7360	0.7870	0.8680	0.9220	0.9760	0.9900	1.0040	1.0170	1.0310
SoCalGas	0.8250	0.9370	1.0040	1.0840	1.1370	1.1570	1.1710	1.1860	1.1970
SDG&E	0.1190	0.1570	0.1730	0.1970	0.2100	0.2160	0.2220	0.2280	0.2350
Non-Utility									
Northern California	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200
Southern California	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180
EOR	0.2880	0.2870	0.2840	0.2780	0.2760	0.2750	0.2750	0.2750	0.2740
Canada									
British Columbia	0.2161	0.2502	0.2711	0.2919	0.3152	0.3183	0.3215	0.3247	0.3280
Eastern Canada	0.3150	0.3413	0.3699	0.4144	0.4809	0.4857	0.4906	0.4955	0.5004
Ontario	1.0544	1.1307	1.1967	1.2781	1.3745	1.3883	1.4022	1.4162	1.4303
Western Canada	1.0694	1.2145	1.3036	1.4677	1.6951	1.7120	1.7291	1.7465	1.7639
Mexico									
Baja	0.0050	0.1370	0.1430	0.1500	0.1570	0.1570	0.1570	0.1570	0.1570
North	0.0820	0.0870	0.0910	0.0960	0.0810	0.0810	0.0810	0.0810	0.0810
East	0.0620	0.1390	0.1460	0.1540	0.1290	0.1290	0.1290	0.1290	0.1290
Total									
Lower 48 (No CA)	19.3625	21.2405	22.8691	24.7455	26.2107	27.4484	27.7342	28.3809	28.4310
California	2.0060	2.2060	2.3670	2.5190	2.6370	2.6760	2.7100	2.7440	2.7750
Canada	2.6549	2.9366	3.1412	3.4521	3.8657	3.9043	3.9434	3.9827	4.0227
Mexico	0.1500	0.3630	0.3810	0.3990	0.3670	0.3670	0.3670	0.3670	0.3670

Source:	Lower 48 (Except California) -	GRI Baseline Projection Databook (1996)
	California -	1996 Electricity Report
	Canada -	Canadian Gas Association
	Mexico -	Energy Information Administration

Notes:
1) Data after 2010 are extrapolations.
2) Noncore demand includes oil consumption on a gas equivalent basis of noncore facilities with fuel switching capability.
3) California non-utility demand is only natural gas.

Statewide Natural Gas Demand Summary
(Utility and Nonutility)
Base Case

mmcfd

Year	Res	Comm	NGV	Ind	TEOR	Cogen	EG	TOTAL
1990	1,393	603	0	791	695	363	1,245	5,090
1991	1,368	648	0	853	814	389	1,234	5,307
1992	1,286	624	0	777	791	451	1,535	5,464
1993	1,346	485	0	834	728	455	1,246	5,094
1994	1,398	501	0	870	726	455	1,600	5,550
1995	1,281	483	0	946	728	462	1,031	4,930
1996	1,268	522	0	996	908	410	816	4,920
1997	1,283	558	4	1014	830	527	1,139	5,356
1998	1,284	566	6	1041	837	558	1,144	5,436
1999	1,288	575	8	1071	836	560	1,189	5,528
2000	1,292	584	11	1108	825	592	1,291	5,702
2001	1,297	592	21	1128	818	592	1,323	5,771
2002	1,302	600	28	1136	814	607	1,451	5,938
2003	1,307	607	35	1152	806	600	1,459	5,966
2004	1,313	615	40	1165	795	608	1,513	6,050
2005	1,321	622	44	1174	787	624	1,486	6,058
2006	1,329	630	48	1183	784	634	1,642	6,249
2007	1,337	636	51	1199	781	626	1,654	6,284
2008	1,346	642	54	1214	778	630	1,731	6,395
2009	1,356	648	56	1227	773	639	1,768	6,467
2010	1,366	654	59	1236	770	653	1,760	6,498
2011	1,376	660	61	1246	767	658	1,827	6,595
2012	1,387	666	62	1260	761	664	1,894	6,694
2013	1,398	672	64	1273	756	663	1,937	6,763
2014	1,410	678	65	1283	754	664	1,976	6,829
2015	1,421	684	65	1289	748	672	2,025	6,904
2016	1,432	691	65	1292	744	676	2,078	6,978
2017	1,447	697	65	1297	741	680	2,131	7,058

Source:

Historic 1990-1996 from a combination of QFER Form 4, 6 and 7, and Cal Gas Report.

Forecasted years 1997 and onward:

Res, Comm, Ind demand from DAO Jan 1998 Demand forecast.
TEOR is from Dec 12 , 1997 NARG run. Includes both steaming and cogen.
Cogen and UEG from EAO Jan 16, 1997 forecast.
EG includes Coolwater facility. Cogen includes SMUD.
NGV from DAO.

Note: * Cogen does not include TEOR.

California Statewide Summary
Utility Natural Gas Demand Forecast
Base Case

mmcfd

	Core				**Noncore**					
Year	**Res**	**Comm**	**Indust**	**NGV**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**TOTAL**
1990	1,393	388	167	0	213	529	537	363	1,245	4,834
1991	1,368	397	185	0	248	542	622	389	1,234	4,985
1992	1,286	373	182	0	248	494	337	451	1,535	4,907
1993	1,346	371	137	0	111	596	203	455	1,246	4,465
1994	1,398	378	140	0	121	629	165	455	1,600	4,886
1995	1,281	352	133	0	128	712	161	462	1,031	4,260
1996	1,268	380	148	0	139	748	162	410	816	4,071
1997	1,283	406	145	4	152	765	162	527	1,139	4,584
1998	1,284	412	150	6	154	788	162	558	1,144	4,658
1999	1,288	419	155	8	157	813	162	560	1,189	4,750
2000	1,292	425	161	11	159	844	164	592	1,291	4,938
2001	1,297	431	164	21	161	860	167	592	1,323	5,017
2002	1,302	437	166	28	163	867	170	607	1,451	5,190
2003	1,307	442	168	35	165	880	173	600	1,459	5,229
2004	1,313	448	171	40	167	891	175	608	1,513	5,326
2005	1,321	453	172	44	169	898	179	624	1,486	5,346
2006	1,329	458	174	48	171	906	183	634	1,642	5,544
2007	1,337	463	176	51	173	919	187	626	1,654	5,586
2008	1,346	467	179	54	174	932	191	630	1,731	5,705
2009	1,356	472	181	56	176	942	195	639	1,768	5,785
2010	1,366	476	183	59	178	950	196	653	1,760	5,821
2011	1,376	480	185	61	179	958	198	658	1,827	5,922
2012	1,387	485	187	62	181	970	199	664	1,894	6,030
2013	1,398	489	189	64	182	981	201	663	1,937	6,104
2014	1,410	494	191	65	184	989	203	664	1,976	6,174
2015	1,421	498	192	65	186	993	203	672	2,025	6,256
2016	1,432	503	192	65	188	996	204	676	2,078	6,334
2017	1,447	508	193	65	189	1,001	204	680	2,131	6,418

Source:
Historic 1989-1996 a combination of QFER Form 4, 6 and 7, and Cal Gas Report.
Forecasted years 1997 and onward:
Res, Comm, Ind demand DAO Jan 1998 Demand forecast.
TEOR is Dec 12 , 1997 NARG. Includes both steaming and cogen.
Cogen and UEG EAO Jan 16, 1997 forecast.
UEG includes Coolwater facility. Cogen includes SMUD.
NGV DAO.
Note: *Cogen does not include TEOR.

PG&E Service Area
Utility Natural Gas Demand Forecast
Base Case

mmcfd

	Core				Noncore					
Year	**Res**	**Comm**	**Indust**	**NGV**	**Comm**	**Indust**	**TEOR**	**Cogen***	**EG**	**TOTAL**
1990	562	158	56	0	157	273	94	92	682	2,076
1991	578	164	54	0	192	258	139	120	626	2,131
1992	522	144	58	0	192	222	69	176	755	2,139
1993	564	165	62	0	53	375	25	158	494	1,896
1994	587	171	57	0	60	392	18	142	747	2,174
1995	525	152	57	0	58	444	18	142	364	1,760
1996	521	182	52	0	69	410	6	141	318	1,700
1997	541	183	54	1	69	423	30	285	563	2,149
1998	542	184	56	1	70	435	53	300	542	2,181
1999	543	186	57	1	70	447	77	301	555	2,238
2000	544	188	59	2	71	463	83	331	595	2,336
2001	546	189	60	3	72	471	90	331	589	2,352
2002	547	191	61	4	72	476	96	345	593	2,386
2003	549	192	62	5	73	482	103	337	636	2,440
2004	551	194	62	6	73	487	110	343	602	2,429
2005	554	195	63	7	74	491	115	358	612	2,467
2006	557	196	63	7	74	495	119	368	696	2,576
2007	560	197	64	8	74	501	124	360	680	2,569
2008	563	198	65	8	75	508	129	363	711	2,620
2009	566	198	66	9	75	513	134	372	747	2,680
2010	570	199	66	9	75	517	136	386	725	2,684
2011	575	200	67	9	76	521	138	391	724	2,700
2012	579	201	67	9	76	527	139	397	774	2,769
2013	584	201	68	10	76	532	141	396	749	2,756
2014	588	202	69	10	76	536	142	397	766	2,787
2015	593	203	69	10	77	539	142	405	789	2,827
2016	598	204	69	10	77	541	142	409	802	2,851
2017	605	205	70	10	77	543	142	413	815	2,879

Source:
Historic 1989-1996 a combination of QFER Form 4, 6 and 7, and Cal Gas Report.
Forecasted years 1997 and onward:
Res, Comm, Ind demand DAO Jan 1998 Demand forecast.
TEOR is Dec 12 , 1997 NARG. Includes both steaming and cogen.
Cogen and UEG EAO Jan 16, 1997 forecast.
UEG includes Coolwater facility. Cogen includes SMUD.
NGV DAO.
Note: *Cogen does not include TEOR.

SoCal Gas Service Area
Utility Natural Gas Demand Forecast
Base Case

mmcfd

	Core				Noncore					
Year	**Res**	**Comm**	**Indust**	**NGV**	**Comm**	**Indust**	**TEOR**	**Cogen***	**EG**	**TOTA**
1990	743	205	101	0	50	250	443	243	468	2,502
1991	701	207	110	0	50	271	483	228	504	2,554
1992	682	203	105	0	49	261	268	247	651	2,466
1993	695	182	65	0	49	215	178	254	632	2,269
1994	719	183	72	0	51	228	147	272	743	2,415
1995	671	177	65	0	59	256	143	275	560	2,206
1996	661	176	82	0	58	324	156	229	380	2,066
1997	661	181	85	3	60	336	132	208	463	2,130
1998	662	185	87	5	62	347	109	209	492	2,157
1999	664	190	90	6	63	358	85	210	541	2,207
2000	666	193	94	9	64	373	81	212	594	2,286
2001	668	197	96	17	66	381	77	212	631	2,345
2002	671	201	97	23	67	384	73	213	680	2,408
2003	674	204	98	28	68	390	70	214	663	2,409
2004	677	208	100	32	69	396	66	216	734	2,498
2005	681	211	100	35	70	399	65	217	706	2,486
2006	686	215	101	38	72	403	64	217	756	2,551
2007	690	218	103	41	73	409	62	217	767	2,580
2008	695	221	104	43	74	415	61	218	801	2,633
2009	700	225	106	45	75	420	60	218	816	2,664
2010	706	228	107	47	76	424	60	218	826	2,691
2011	711	231	108	48	77	427	60	218	874	2,754
2012	716	234	109	50	78	433	60	218	886	2,784
2013	722	237	110	51	79	438	60	218	940	2,855
2014	727	240	111	52	80	442	60	218	954	2,884
2015	732	243	112	52	81	444	61	218	981	2,924
2016	737	247	112	52	82	445	61	218	1,012	2,966
2017	744	250	112	52	83	447	62	218	1,043	3,011

Source:
Historic 1989-1996 a combination of QFER Form 4, 6 and 7, and Cal Gas Report.
Forecasted years 1997 and onward:
Res, Comm, Ind demand DAO Jan 1998 Demand forecast.
TEOR is Dec 12 , 1997 NARG. Includes both steaming and cogen.
Cogen and UEG EAO Jan 16, 1997 forecast.
UEG includes Coolwater facility. Cogen includes SMUD.
NGV DAO.
Note: *Cogen does not include TEOR.

SDG&E Service Area
Utility Natural Gas Demand Forecast
Base Case

mmcfd

	Core				Noncore					
Year	**Res**	**Comm**	**Indust**	**NGV**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**TOTAL**
1990	88	25	10	0	6	5	NA	28	94	257
1991	89	26	21	0	6	12	NA	42	104	300
1992	81	26	19	0	6	11	NA	28	130	302
1993	87	24	9	0	9	7	NA	43	120	299
1994	92	24	11	0	10	9	NA	41	110	297
1995	85	22	12	0	12	11	NA	45	107	294
1996	86	22	14	0	12	13	NA	40	118	305
1997	81	42	7	0	22	6	NA	34	113	305
1998	81	42	7	0	23	7	NA	49	110	319
1999	82	43	7	0	23	7	NA	49	93	305
2000	82	44	8	1	24	7	NA	49	102	316
2001	83	44	8	1	24	8	NA	49	103	319
2002	83	45	8	1	24	8	NA	49	178	397
2003	84	45	8	2	24	8	NA	49	160	381
2004	85	46	9	2	25	8	NA	49	177	400
2005	85	46	9	2	25	8	NA	49	168	393
2006	86	47	9	2	25	9	NA	49	190	418
2007	87	48	9	3	26	9	NA	49	207	437
2008	88	48	10	3	26	9	NA	49	219	452
2009	89	49	10	3	26	9	NA	49	205	440
2010	90	49	10	3	27	10	NA	49	209	447
2011	91	50	10	3	27	10	NA	49	229	469
2012	92	50	11	3	27	10	NA	49	234	477
2013	93	51	11	3	28	10	NA	49	248	493
2014	94	52	11	3	28	11	NA	49	256	504
2015	96	52	11	3	28	11	NA	49	255	505
2016	97	53	11	3	28	11	NA	49	264	517
2017	98	53	12	3	29	11	NA	49	273	529

Source:

Historic 1989-1996 a combination of QFER Form 4, 6 and 7, and Cal Gas Report.

Forecasted years 1997 and onward:

Res, Comm, Ind demand DAO Jan 1998 Demand forecast.
TEOR is Dec 12 , 1997 NARG. Includes both steaming and cogen.
Cogen and UEG EAO Jan 16, 1997 forecast.
UEG includes Coolwater facility. Cogen includes SMUD.
NGV DAO.

Note: *Cogen does not include TEOR.

Thermal Enhanced Oil Recover Operations
Fuel Requirements
Base Case

mmcfd equivalent

	Natural Gas			Oil	Fuel
Year	**Steam**	**Cogen**	**Total**	**Total**	**Total**
1990	422	273	695	91	786
1991	516	298	814	47	861
1992	505	286	791	13	804
1993	429	299	728	2	730
1994	438	288	726	6	732
1995	421	306	728	0	728
1996	603	305	908	0	908
1997	594	236	830	0	830
1998	601	236	837	0	837
1999	600	236	836	0	836
2000	589	236	825	0	825
2001	582	236	818	0	818
2002	578	236	814	0	814
2003	570	236	806	0	806
2004	559	236	795	0	795
2005	551	236	787	0	787
2006	548	236	784	0	784
2007	545	236	781	0	781
2008	542	236	778	0	778
2009	537	236	773	0	773
2010	534	236	770	0	770
2011	531	236	767	0	767
2012	525	236	761	0	761
2013	520	236	756	0	756
2014	518	236	754	0	754
2015	512	236	748	0	748
2016	508	236	744	0	744
2017	505	236	741	0	741

Source:
Historical Data for 1990-1995 which is based on PIIRA data for steaming and Division of Oil, Gas and Geothermal Resources for cogeneration. These values have been revised by CEC staff.

Forecasted oil burn is Base Case NARG run.

Note:
There could be up to 200 mmcfd in equivalent oil burn for steaming operations where gas does not compete with oil.

APPENDIX D
Transportation Costs, Capacities, Line Losses for NARG Model Corridors

NARG Sector	NARG Activity	Interstate Pipeline Corridors	FR95 '93$/mcf	FR97 '95$/mcf	Maximum Pipeline Capacity		Line Losses	Source of FR97 Transport Cost
					TCF	BCF/D		
1	5	ANGTS to Alberta	4.550	4.550	0.700	1.918	8.00%	1995 Fuels Report
1	6	TAGS to S Alaska	1.800	1.800	N/A	N/A	3.00%	1995 Fuels Report
2	9	S Alaska to Asia	1.700	1.700	0.420	1.151	0.00%	1995 Fuels Report
3	11	San Juan to Topock (EP-N)	0.167	0.164	1.240	3.397	2.50%	50% of EPNG/TW SJ-CA Rate (Effective 7/97)
3	6	San Juan to Rocky Mtns	0.254	0.276	0.122	0.334	1.50%	Northwest Pipeline
3	18	San Juan to Anadarko	--	0.279	0.035	0.096	1.60%	CIG Rate (Off-System)
3	9	San Juan to Permian	0.187	0.175	0.448	1.227	5.00%	EPNG/TW Combined (Effective 7/97)
3	5	Topock to EOR (Via Mojave)	0.485	0.485	0.146	0.400	2.50%	50% EPNG: SJ to CA Border + Mojave (Effective 7/97)
3	3	Topock to Southern CA Supply (Via EP-N)	0.167	0.164	0.526	1.441	2.50%	50% EPNG/TW SJ-CA Rate (Effective 7/97)
3	4	Topock to Northern CA Supply (Via EP-N)	0.167	0.164	0.416	1.140	2.50%	50% EPNG/TW SJ-CA Rate (Effective 7/97)
3	7	Topock to SW Desert - AZ/NM (Via EP-N)	--	0.077	0.292	0.800	2.50%	EPNG SJ to AZ/NM Tariff - NARG Rate (SJ-Topock)
3	13	Topock to Blythe (Via Havasu Crossover)	0.000	0.000	N/A	N/A	0.00%	Rate Incorporated in Other Corridors
3	15	Topock to SW Desert - NV (Via EP-N)	--	0.103	0.082	0.225	2.50%	EPNG SJ to NV Tariff - NARG Rate (SJ-Topock)
4	18	Rocky Mtns to EOR (Through 2009)	0.674	0.402	0.256	0.701	1.00%	100% Kern River (Years 1-15)
4	18	Rocky Mtns to EOR (Beyond 2009)	0.402	0.402	0.256	0.701	1.00%	100% Kern River (Years 16-25)
4	14	Rocky Mtns to San Juan Basin	0.245	0.276	0.233	0.638	1.50%	Northwest Pipeline
4	15	Rocky Mtns to WNC Demand	0.270	0.236	0.404	1.108	0.50%	Trailblazer, KN Interstate
4	16	Rocky Mtns to Rocky Mtn Demand	--	0.185	0.571	1.564	1.50%	Questar Pipeline, CIG (On-System Rate)
4	17	Rocky Mtn to Anadarko	0.207	0.228	0.237	0.649	1.60%	CIG, Williams Natural Gas, KN Interstate
4	25	Rocky Mtn to Pacific Northwest	--	0.276	0.162	0.444	1.60%	Northwest Pipeline
5	13	NGPlains to Rocky Mtn Demand (Montana)	--	0.350	0.127	0.348	3.40%	Williston Basin
5	14	NGPlains to WNC Demand	0.564	0.350	0.075	0.205	3.40%	Williston Basin
5	16	NGPlains to Rocky Mtn Demand (WY/CO)	--	0.174	0.100	0.274	1.40%	CIG (On-System Rate)
6	4	Anadarko to WNC Demand	0.207	0.186	2.207	6.047	2.90%	Northern Natural, Panhandle Eastern, Williams, KN Interstate
6	6	Anadarko to Permian Basin	0.169	0.104	0.735	2.014	1.40%	EPNG (Anadarko-Production Area)
6	7	Anadarko to WSC Demand	0.176	0.192	3.016	8.263	1.20%	Spot Price Differential (1/95-12/95)
6	8	Anadarko to ESC Demand	0.148	0.247	0.188	0.515	2.50%	Noram Gas Transmission
7	11	Permian to El Paso -South Allocation (Blythe)	0.164	0.162	0.457	1.252	2.50%	50% of EPNG: Permian to CA (Effective 7/97)
7	7	Permian to Anadarko	0.086	0.104	0.653	1.789	1.40%	EPNG (Permian-Production Area)
7	9	Permian to WSC Demand	0.091	0.091	0.475	1.301	1.20%	Valero
7	10	Permian to San Juan (EP-N)	0.000	0.000	0.522	1.430	2.50%	Rate Incorporated in Other Corridors
7	13	Permian to Gulf	0.234	0.234	0.602	1.649	1.00%	Valero
7	8	Blythe (EP-S Allocation) to SW Desert - AZ/NM	--	0.077	0.188	0.515	2.50%	EPNG Permian to AZ/NM Tariff - NARG Rate (Permian-Blythe)
7	12	Blythe (EP-S Allocation) to Mexico	--	0.077	0.168	0.460	2.50%	EPNG Permian to AZ/NM Tariff - NARG Rate (Permian-Blythe)
7	21	Blythe to Southern CA Supply (Via EP-S)	0.164	0.162	0.515	1.411	2.50%	50% of EPNG: Permian to CA (Effective 7/97)
8	8	Gulf Coast to WSC Demand	0.151	0.127	7.290	19.973	1.10%	Tennessee Gas, Transcontinental, Texas Eastern
8	9	Gulf Coast to Permian Basin	0.234	0.234	0.420	1.151	1.00%	Valero
8	10	Gulf Coast to ESC Demand	0.158	0.172	7.584	20.778	1.20%	Tennessee Gas, Transcontinental, Texas Eastern, Southern Natura
8	15	Gulf Coast to Mexico Demand (East)	--	0.040	0.494	1.353	0.50%	1995 Fuels Report Sensitivity

NARG Sector	NARG Activity	Interstate Pipeline Corridors	Fr95 ‘93$/mcf	FR97 ‘95$/mcf	Maximum Pipeline Capacity		Line Losses	Source of FR97 Transport Cost
					TCF	BCF/D		
9	8	N Central to ENC Demand	0.308	0.307	0.408	1.118	3.00%	East Ohio Off-System Rate
9	9	N Central to ESC Demand	0.308	0.307	0.070	0.192	5.00%	East Ohio Off-System Rate
10	11	Appalachia to S Atantic Demand	0.434	0.239	0.622	1.704	2.30%	Columbia Gas
10	12	Appalachia to Mid-Atlantic Demand	0.491	0.171	0.664	1.819	2.40%	National Fuel, Columbia Gas, CNG, Equitrans
12	3	Mexico to Gulf Coast	1.050	1.050	0.500	1.370	0.00%	1995 Fuels Report
13	10	Sumas to Pacific NW	0.254	0.276	0.343	0.940	1.60%	Northwest Pipeline
13	11	S Alberta to Rocky Mtn Demand (Montana)	0.183	0.182	0.040	0.110	2.00%	Montana Power
13	7	S Alberta to Stanfield	0.210	0.116	0.909	2.490	1.10%	45.3% of PGT Rolled-in Tariff
13	15	Stanfield to Pacific NW (Reno Lateral)	0.324	0.276	0.198	0.542	1.60%	Northwest Pipeline
13	21	Stanfield to Malin	0.254	0.140	0.657	1.800	1.40%	54.7% of PGT Rolled-in Tariff
13	22	Stanfield to PNW Demand (Via NWPL)	0.254	0.276	0.054	0.148	1.50%	Northwest Pipeline
13	9	Malin to PG&E (PG&E Line 400))	0.155	0.215	0.381	1.044	0.00%	PG&E Noncore Backbone Rate (Reported in Gas Accord Filing)
13	8	Malin to Southern CA Supply (PG&E Line 401)	0.337	0.337	0.219	0.600	3.50%	PG&E Tariffs (Effective 5/94)
13	19	Malin to Northern CA Supply (PG&E Line 401)	0.215	0.215	0.276	0.756	3.50%	PG&E Tariffs (Effective 5/94)
13	24	Malin to PNW Demand (Reno)	--	0.470	0.041	0.112	2.00%	Tuscarora Pipeline
13	12	East Montana to WNC (Northern Border)	0.444	0.337	0.800	2.192	2.70%	Northern Border (Monchy-Ventura)
13	16	WNC to ENC (Northern Border)	0.079	0.146	0.492	1.348	1.30%	Northern Border (Ventura-Harper and Harper-Manhattan)
13	13	West Minn to ENC	0.362	0.219	0.494	1.353	6.50%	Viking Gas, Great Lakes
13	14	New York to Mid Atlantic	0.034	0.334	0.756	2.071	1.60%	Tennessee Gas, Iroquois
13	20	Vermont to New England	--	0.333	0.023	0.063	0.50%	From Gaz de Metropolitain Filing. ($0.35 in 1997$)
14	3	LNG to Gulf	2.250	2.250	0.365	1.000	0.00%	1995 Fuels Report
14	4	LNG to So Atlantic	1.880	1.880	0.219	0.600	0.00%	1995 Fuels Report
14	5	LNG to Mid Atlantic	1.950	1.950	0.548	1.501	0.00%	1995 Fuels Report
14	9	LNG to New England	1.770	1.770	0.164	0.449	0.00%	1995 Fuels Report
15	7	Pacific NW to PGT for Delivery to CA Border	0.254	0.000	0.073	0.200	0.00%	Incorporated in Other Corridors
15	8	Pacific NW to Rocky Mtn Supply	0.254	0.000	0.109	0.299	0.00%	Incorporated in Other Corridors
15	9	Pacific NW to PNW Demand (Reno)	--	0.259	0.059	0.162	2.50%	Paiute Pipeline
15	10	Pacific NW to Rocky Mtn Demand (Idaho)	--	0.000	N/A	0.000	1.50%	Incorporated in Other Corridors
16	14	WNC to ENC (Except Northern Border)	0.594	0.143	1.769	4.847	2.90%	Northern Natural, Panhandle Eastern
18	9	ENC to Mid-Atlantic	0.397	0.295	1.601	4.386	1.90%	Texas Eastern, Tennessee Gas, CNG
18	10	ENC to Ontario	0.192	0.142	0.071	0.195	1.00%	Panhandle Eastern
19	13	ESC to ENC	0.169	0.296	4.223	11.570	3.00%	Texas Eastern, Tennessee Gas
19	14	ESC to So Atlantic	0.117	0.142	3.391	9.290	1.70%	Transcontental, Southern Natural
20	13	So Atlantic to Mid-Atlantic	0.207	0.171	1.021	2.797	2.30%	Transco, Columbia, CNG
21	13	Mid-Atlantic to New England	0.350	0.243	0.764	2.093	1.20%	Tennessee Gas, Algonquin, Iroquois
23	2	Southern CA Supply to SoCalGas	0.000	0.000	1.000	2.740	0.50%	1995 Fuels Report
23	3	Southern CA Supply to SDG&E	0.354	0.292	0.146	0.400	0.50%	SoCalGas Tariff Sheet 27591-G, Effective 1/1/96.
23	4	Southern CA Supply to EOR	0.098	0.098	0.146	0.400	0.50%	Avg California Transport Rate

NARG Sector	NARG Activity	Interstate Pipeline Corridors	FR95 ‘93$/mcf	Fr97 ‘95$/mcf	Maximum Pipeline Capacity TCF	BCF/D	Line Losses	Source of FR97 Transport Cost
23	13	Southern CA Supply (Wheeler Ridge)	0.000	0.000	0.197	0.540	0.00%	SoCalGas Tariff Sheet 27685-G, Effective 3/1/96.
23	14	Southern CA Supply Direct Link	0.098	0.098	0.256	0.701	0.50%	Avg California Transport Rate
23	16	Southern CA Supply to Mexico (Baja)	--	0.200	0.197	0.540	2.00%	1995 Fuels Report Sensitivity
24	2	Northern CA Supply to PG&E	0.000	0.215	0.964	2.641	0.50%	PG&E Noncore Backbone Rate (Reported in Gas Accord Filing)
24	10	Northern CA Supply Direct Link	0.098	0.098	0.110	0.301	2.00%	Avg California Transport Rate
25	13	SoCalGas to EOR	0.421	0.341	0.160	0.438	0.50%	SoCalGas Tariff Sheet 27586-G, Effective 1/1/96.
26	13	PG&E to EOR	0.234	0.224	0.150	0.411	0.50%	CPUC Decision 95-12-053, 12/95.
28	5	EOR to Southern CA Supply	0.000	0.000	0.146	0.400	0.00%	1995 Fuels Report
28	4	EOR to Northern CA Supply (Via KR/Mojave)	0.000	0.000	0.073	0.200	0.00%	PG&E Kern River Station Charge
1,2	9	BC to BC Demand	0.150	0.158	0.219	0.600	1.60%	Westcoast Inland Toll
1,2	5	BC to Washington	0.218	0.232	0.068	0.186	1.00%	Westcoast to Alberta Toll
1,2	6	BC to Alberta	0.071	0.070	0.365	1.000	1.40%	Westcoast Export Toll
2,2	5	Alberta to Western Canada	0.085	0.105	1.071	2.934	1.20%	NOVA Provincial
2,2	6	Alberta to East Montana	0.228	0.267	0.818	2.240	1.20%	NOVA export + Foothills to N.Border
2,2	7	Alberta to Saskatchewan	0.276	0.345	2.332	6.389	1.20%	NOVA export + TCPL to Saskatchewan
2,2	8	Alberta to S Alberta	0.223	0.258	1.190	3.260	1.20%	NOVA export + ANG to PGT
3,2	4	Saskatchewan to Western Canada	0.219	0.245	0.200	0.548	1.30%	TCPL to Saskatchewan + NOVA Provincial
3,2	5	Saskatchewan to Ontario	0.422	0.440	1.800	4.932	1.30%	TCPL to N Ontario - Saskatchewan
3,2	6	Saskatchewan to West Minn	0.117	0.122	0.433	1.186	1.30%	TCPL to Emerson - Saskatchewan
4,2	4	N Canada Supply to Alberta	1.540	1.540	0.438	1.200	4.00%	1995 Fuels Report
5,2	4	E Canada Supply to New England	1.600	0.970	0.146	0.400	8.00%	Natural GasTrade Publications
7,2	7	E Canada Demand to Vermont	N/A	0.000	N/A	0.000	N/A	Incorporated in Other Corridors
9,2	7	Ontario Demand to East Canada Demand	0.111	0.119	0.438	1.200	3.00%	TCPL to East of Ontario - N Ontario
9,2	8	Ontario to New York	0.150	0.157	N/A	0.000	1.40%	TCPL to Niagara - N Ontario

APPENDIX E
California Natural Gas Border Supply And Price Forecast

California Summary
Natural Gas Supply Forecast
Base Case

mmcfd

Supply Source	1994	1999	2004	2009	2014	2019
California Production						
So Calif Onshore	463	488	540	471	490	474
No Calif Onshore	230	167	241	288	345	389
State Offshore	19	5	11	25	36	36
MMS Offshore	140	44	145	153	159	164
Total Calif Production	852	704	937	937	1,030	1,063
Southwest						
Topock	1,797	1,849	2,077	2,178	2,233	2,326
Bythe via Havasu	271	797	1,071	1,142	1,164	1,132
Bythe via Permian	732	342	318	296	326	411
Total Southwest	2,800	2,989	3,466	3,616	3,723	3,868
Rocky Mountains						
TEOR	307	326	315	304	290	285
Southern Calif	260	93	351	397	460	501
Northern Calif	96	112	129	142	153	178
Total Rocky Mountains	663	532	795	844	904	964
Canada at Malin						
PG&E	1,304	1,304	1,405	1,605	1,723	1,789
SoCal Gas	312	186	249	323	378	389
Total Canada	1,616	1,490	1,655	1,929	2,101	2,178
Total Supply	5,932	5,715	6,852	7,326	7,759	8,074
Supply to Mexico	0	14	375	392	836	888
Net Supply to California	5,932	5,701	6,477	6,934	6,923	7,186

California Summary
Natural Gas Border Price Forecast
Base Case

1995 $/mcf

Supply Source	1994	1999	2004	2009	2014	2019
California Production						
So Calif Onshore	na	1.79	2.04	2.26	2.49	2.72
No Calif Onshore	na	1.91	2.06	2.24	2.44	2.65
State Offshore	na	2.49	2.40	2.54	2.79	3.05
MMS Offshore	na	2.16	2.11	2.35	2.60	2.82
Total Calif Production	na	1.85	2.06	2.28	2.50	2.72
Southwest						
Topock	na	1.68	1.90	2.08	2.30	2.51
Bythe via Havasu	na	1.68	1.90	2.08	2.30	2.51
Bythe via Permian	na	1.78	1.94	2.13	2.38	2.54
Total Southwest	na	1.69	1.90	2.08	2.31	2.51
Rocky Mountains						
TEOR	na	1.76	1.97	2.16	2.37	2.58
Southern Calif	na	1.76	1.97	2.16	2.37	2.58
Northern Calif	na	1.76	1.97	2.16	2.37	2.58
Total Rocky Mountains	na	1.76	1.97	2.16	2.37	2.58
Canada at Malin						
Northern Calif	na	1.53	1.70	1.85	2.06	2.25
Southtern Calif	na	1.53	1.70	1.85	2.06	2.25
Total Canada	na	1.53	1.70	1.85	2.06	2.25
Total Supply Cost	na	1.67	1.88	2.06	2.27	2.48

PG&E Utility Service
Natural Gas Supply Forecast
Base Case

mmcfd

Supply Source	1994	1999	2004	2009	2014	2019
No. California Production	230	167	241	288	345	389
Southwest	770	614	611	600	575	595
Rocky Mountains	96	112	129	142	153	178
Canada at Malin	1,304	1,575	1,405	1,608	1,721	1,789
Total Supply	2,400	2,468	2,386	2,638	2,795	2,951

PG&E Utility Service
Natural Gas Border Price Forecast
Base Case

1995 $/mcf

Supply Source	1994	1999	2004	2009	2014	2019
No. California Production	na	1.91	2.06	2.24	2.44	2.65
Southwest	na	1.68	1.90	2.08	2.30	2.51
Rocky Mountains	na	1.76	1.97	2.16	2.37	2.58
Canada at Malin	na	1.53	1.70	1.85	2.06	2.25
Total Supply Cost	na	1.60	1.80	1.96	2.17	2.37

SoCal Gas Utility Service
Natural Gas Supply Forecast
Base Case

mmcfd

Supply Source	1994	1999	2004	2009	2014	2019
So. California Production	471	375	548	521	564	559
Southwest						
Topock	827	1,033	1,252	1,362	1,447	1,518
Bythe via Havasu	271	797	1,071	1,142	1,164	1,132
Bythe via Permian	732	342	318	296	326	411
Total Southwest	1,830	2,173	2,641	2,800	2,937	3,060
Rocky Mountains	260	93	351	397	460	501
Canada at Malin	312	186	249	323	378	389
Total Supply	2,874	2,827	3,789	4,041	4,340	4,510
Supply to Mexico	0	14	375	392	836	888
Net Supply to So Calif	2,874	2,814	3,414	3,649	3,504	3,622

SoCal Gas Utility Service
Natural Gas Border Price Forecast
Base Case

1995 $/mcf

Supply Source	1994	1999	2004	2009	2014	2019
So. California Production	na	1.83	2.06	2.29	2.53	2.76
Southwest						
Topock	na	1.68	1.90	2.08	2.30	2.51
Bythe via Havasu	na	1.68	1.90	2.08	2.30	2.51
Bythe via Permian	na	1.78	1.94	2.13	2.38	2.54
Total Southwest	na	1.69	1.90	2.08	2.31	2.51
Rocky Mountains	na	1.76	1.97	2.16	2.37	2.58
Canada at Malin	na	1.53	1.70	1.85	2.06	2.25
Total Supply Cost	na	1.71	2.13	2.33	2.88	3.15

TEOR Service
Natural Gas Supply Forecast
Base Case

mmcfd

Supply Source	1994	1999	2004	2009	2014	2019
California Production	101	112	99	79	71	66
Southwest	200	203	214	216	211	214
Rocky Mountains	307	326	315	304	290	285
PG&E Supply	19	77	110	134	142	115
SoCal Gas Supply	151	85	66	60	60	63
Total Supply	778	803	803	795	775	742

TEOR Service
Natural Gas Border Price Forecast
Base Case

1995 $/mcf

Supply Source	1994	1999	2004	2009	2014	2019
California Production	na	1.83	2.06	2.29	2.53	2.76
Southwest	na	1.80	2.01	2.20	2.41	2.62
Rocky Mountains	na	1.76	1.97	2.16	2.37	2.58
PG&E Supply	na	2.08	2.13	2.30	2.52	2.70
SoCal Gas Supply	na	2.22	2.49	2.68	2.92	3.12
Total Supply Cost	na	1.86	2.06	2.25	2.47	2.67

APPENDIX F
BASECASE PIPELINE UTILITIZATION RATES

	Basecase Flows (TCF)							Pipeline Utilization Rates					
	1994	1999	2004	2009	2014	2019	Capacity	1994	1999	2004	2009	2014	2019
CALIFORNIA:													
S Cal-SoCal Gas 2,23	0.921	0.873	0.980	1.048	1.129	1.185	1.000	92.1%	87.3%	98.0%	104.8%	112.9%	118.5%
S Cal-SDG&E 3,23	0.112	0.121	0.160	0.175	0.194	0.201	0.146	76.7%	82.9%	109.6%	119.9%	132.9%	137.7%
S Cal-EOR 4,23	0.037	0.041	0.036	0.029	0.026	0.024	0.146	25.3%	28.1%	24.7%	19.9%	17.8%	16.4%
Mexico 16,23	0.000	0.005	0.137	0.143	0.150	0.157	0.197	0.0%	2.5%	69.5%	72.6%	76.1%	79.7%
Wheeler Ridge 13,23	0.208	0.161	0.218	0.262	0.305	0.324	0.197	105.6%	81.7%	110.7%	133.0%	154.8%	164.5%
S Cal Direct Link14,23	0.018	0.018	0.018	0.017	0.017	0.017	0.256	7.0%	7.0%	7.0%	6.6%	6.6%	6.6%
N Cal-PG&E 2,24	0.638	0.589	0.635	0.712	0.756	0.799	0.964	66.2%	61.1%	65.9%	73.9%	78.4%	82.9%
N Cal Direct Link10,24	0.019	0.017	0.017	0.016	0.016	0.016	0.110	17.3%	15.5%	15.5%	14.5%	14.5%	14.5%
SoCal Gas-EOR 13,25	0.055	0.031	0.024	0.022	0.022	0.023	0.160	34.4%	19.4%	15.0%	13.8%	13.8%	14.4%
PG&E-EOR 13,26	0.007	0.028	0.040	0.049	0.052	0.052	0.150	4.7%	18.7%	26.7%	32.7%	34.7%	34.7%
EOR-S Cal 5,28	0.095	0.094	0.128	0.145	0.168	0.183	0.146	65.1%	64.4%	87.7%	99.3%	115.1%	125.3%
EOR-N Cal 4,28	0.035	0.041	0.047	0.052	0.056	0.065	0.073	47.9%	56.2%	64.4%	71.2%	76.7%	89.0%
SAN JUAN TO:													
S Cal (EP-N) 3,3	0.302	0.377	0.457	0.497	0.528	0.554	0.526	57.4%	71.7%	86.9%	94.5%	100.4%	105.3%
N Cal (EP-N) 4,3	0.281	0.224	0.223	0.219	0.210	0.217	0.416	67.5%	53.8%	53.6%	52.6%	50.5%	52.2%
EOR (Mojave) 5,3	0.073	0.074	0.078	0.079	0.077	0.078	0.146	50.0%	50.7%	53.4%	54.1%	52.7%	53.4%
Rockies 6,3	0.000	0.023	0.021	0.017	0.009	0.005	0.122	0.0%	18.9%	17.2%	13.9%	7.4%	4.1%
SW Desert (AZ/NM) 7,3	0.026	0.168	0.216	0.235	0.238	0.232	0.081	32.1%	207.4%	266.7%	290.1%	293.8%	286.4%
Permian(EP-Xover) 9,3	0.283	0.480	0.504	0.531	0.524	0.496	0.448	63.2%	107.1%	112.5%	118.5%	117.0%	110.7%
EP/TW-N Mainline 11,3	0.838	1.210	1.454	1.542	1.572	1.589	1.240	67.6%	97.6%	117.3%	124.4%	126.8%	128.1%
Havasu X-Over 13,3	0.099	0.291	0.391	0.417	0.425	0.413	0.257	38.5%	113.1%	151.9%	162.1%	165.2%	160.5%
SW Desert (LV) 15,3	0.038	0.053	0.063	0.066	0.066	0.066	0.082	46.3%	64.6%	76.8%	80.5%	80.5%	80.5%
Anadarko (Raton) 18,3	0.000	0.052	0.060	0.062	0.064	0.063	0.035	0.0%	148.6%	171.4%	177.1%	182.9%	180.0%
PERMIAN TO:													
Anadarko 7,7	0.441	0.746	0.787	0.776	0.725	0.625	0.653	67.5%	114.2%	120.5%	118.8%	111.0%	95.7%
SW Desert (AZ/NM) 8,7	0.198	0.093	0.088	0.090	0.097	0.113	0.188	105.3%	49.5%	46.8%	47.9%	51.6%	60.1%
WSC 9,7	0.475	0.787	0.854	0.846	0.798	0.753	0.475	100.0%	165.7%	179.8%	178.1%	168.0%	158.5%
SanJuan(EP-Xover)10,7	0.000	0.031	0.045	0.038	0.046	0.075	0.570	0.0%	5.4%	7.9%	6.7%	8.1%	13.2%
EP-S Mainline 11,7	0.483	0.305	0.295	0.294	0.317	0.350	0.457	105.7%	66.7%	64.6%	64.3%	69.4%	76.6%
Gulf 13,7	0.706	0.510	0.612	0.590	0.497	0.462	0.602	117.3%	84.7%	101.7%	98.0%	82.6%	76.7%
EP-S/East of CA 19,7	0.000	0.078	0.085	0.089	0.088	0.081	0.066	0.0%	118.7%	129.4%	135.5%	133.9%	123.3%
Blythe-SCA 21,7	0.357	0.330	0.411	0.425	0.444	0.470	0.515	69.3%	64.1%	79.8%	82.5%	86.2%	91.3%
ANADARKO TO:													
WNC 4,6	1.899	1.666	1.702	1.693	1.780	1.666	2.207	86.0%	75.5%	77.1%	76.7%	80.7%	75.5%
Permian 6,6	0.177	0.094	0.067	0.054	0.066	0.064	0.735	24.1%	12.8%	9.1%	7.3%	9.0%	8.7%
WSC 7,6	1.226	1.462	1.546	1.319	1.193	0.861	3.016	40.6%	48.5%	51.3%	43.7%	39.6%	28.5%
ESC 8,6	0.090	0.242	0.250	0.246	0.244	0.238	0.188	47.9%	128.7%	133.0%	130.9%	129.8%	126.6%

APPENDIX F
BASECASE PIPELINE UTILITIZATION RATES

		Basecase Flows (TCF)							**Pipeline Utilization Rates**				
	1994	1999	2004	2009	2014	2019	Capacity	1994	1999	2004	2009	2014	2019
ROCKIES TO:													
San Juan 14,4	0.083	0.054	0.061	0.114	0.174	0.265	0.233	35.6%	23.2%	26.2%	48.9%	74.7%	113.7%
WNC 15,4	0.173	0.621	0.697	0.761	0.959	1.390	0.404	42.8%	153.7%	172.5%	188.4%	237.4%	344.1%
RM Demand 16,4	0.377	0.368	0.413	0.462	0.538	0.587	0.571	66.0%	64.4%	72.3%	80.9%	94.2%	102.8%
Anadarko 17,4	0.138	0.306	0.342	0.372	0.397	0.411	0.237	58.2%	129.1%	144.3%	157.0%	167.5%	173.4%
CA (Kern River) 19,4	0.243	0.255	0.290	0.307	0.331	0.353	0.256	94.9%	99.6%	113.3%	119.9%	129.3%	137.9%
NV (Kern River) 20,4	0.019	0.015	0.017	0.020	0.023	0.025	0.256	7.4%	5.9%	6.6%	7.8%	9.0%	9.8%
Utah (Kern River)21,4	0.002	0.003	0.002	0.002	0.001	0.001	0.256	0.8%	1.2%	0.8%	0.8%	0.4%	0.4%
Kern River Composite	0.264	0.273	0.309	0.329	0.355	0.379	0.256	103.1%	106.6%	120.7%	128.5%	138.7%	148.0%
PNW 25,4	0.073	0.096	0.124	0.179	0.199	0.211	0.162	45.1%	59.3%	76.5%	110.5%	122.8%	130.2%
GULF COAST TO:													
WSC 8,8	3.586	3.508	3.969	4.453	4.931	5.477	7.290	49.2%	48.1%	54.4%	61.1%	67.6%	75.1%
Permian 9,8	0.000	0.034	0.050	0.080	0.152	0.243	0.420	0.0%	8.1%	11.9%	19.0%	36.2%	57.9%
ESC 10,8	6.124	6.324	6.873	7.501	8.215	8.861	7.584	80.7%	83.4%	90.6%	98.9%	108.3%	116.8%
Mexico 15,8	0.035	0.062	0.139	0.146	0.154	0.129	0.494	7.1%	12.6%	28.1%	29.6%	31.2%	26.1%
NGP TO:													
RM Demand(Montana)13,5	0.029	0.024	0.033	0.046	0.060	0.070	0.127	22.8%	18.9%	26.0%	36.2%	47.2%	55.1%
WNC 14,5	0.093	0.109	0.121	0.132	0.142	0.205	0.075	124.0%	145.3%	161.3%	176.0%	189.3%	273.3%
RM Demand (WY/CO) 16,5	0.072	0.127	0.140	0.150	0.158	0.165	0.100	72.0%	127.0%	140.0%	150.0%	158.0%	165.0%
PNW TO:													
CA (NWPL/PGT) 7,15	0.000	0.034	0.049	0.061	0.062	0.071	0.073	0.0%	46.6%	67.1%	83.6%	84.9%	97.3%
PacNW-Rockies 8,15	0.000	0.021	0.017	0.012	0.007	0.005	0.109	0.0%	19.3%	15.6%	11.0%	6.4%	4.6%
Reno (Paiute) 9,15	0.076	0.048	0.052	0.060	0.066	0.069	0.059	128.8%	81.4%	88.1%	101.7%	111.9%	116.9%
REST OF U.S.:													
N Central-ENC 8,9	0.110	0.412	0.504	0.551	0.596	0.633	0.408	27.0%	101.0%	123.5%	135.0%	146.1%	155.1%
N Central-ESC 9,9	0.069	0.078	0.087	0.094	0.100	0.104	0.070	98.6%	111.4%	124.3%	134.3%	142.9%	148.6%
Appalachia-S Atl 11,10	0.081	0.122	0.207	0.248	0.362	0.449	0.622	13.0%	19.6%	33.3%	39.9%	58.2%	72.2%
Appalachia-M Atl 12,10	0.438	0.541	0.764	0.782	0.881	0.982	0.664	66.0%	81.5%	115.1%	117.8%	132.7%	147.9%
WNC-ENC 14,16	1.164	1.363	1.367	1.291	1.305	1.389	1.769	65.8%	77.0%	77.3%	73.0%	73.8%	78.5%
ENC-M Atl 9,18	1.227	1.119	1.087	1.100	1.166	1.285	1.601	76.6%	69.9%	67.9%	68.7%	72.8%	80.3%
ENC-Ontario 10,18	0.030	0.052	0.056	0.069	0.085	0.098	0.071	42.3%	73.2%	78.9%	97.2%	119.7%	138.0%
ESC-ENC 13,19	3.129	2.184	2.277	2.543	2.920	3.185	4.223	74.1%	51.7%	53.9%	60.2%	69.1%	75.4%
ESC-S Atl 14,19	2.160	3.309	3.646	3.912	4.075	4.338	3.391	63.7%	97.6%	107.5%	115.4%	120.2%	127.9%
S Atl-M Atl 13,20	0.572	1.227	1.292	1.315	1.365	1.439	1.021	56.0%	120.2%	126.5%	128.8%	133.7%	140.9%
M Atl-New Eng 13,21	0.525	0.742	0.801	0.872	0.929	0.964	0.764	68.7%	97.1%	104.8%	114.1%	121.6%	126.2%
Tuscarora 24,13	0.000	0.024	0.028	0.028	0.028	0.030	0.041	0.0%	59.2%	69.1%	69.1%	69.1%	74.0%

APPENDIX F
BASECASE PIPELINE UTILITIZATION RATES

	Basecase Flows (TCF)							Pipeline Utilization Rates					
	1994	1999	2004	2009	2014	2019	Capacity	1994	1999	2004	2009	2014	2019
CANADIAN PIPELINE LINKS:													
BC-BC Demand 9,1	0.189	0.218	0.256	0.278	0.300	0.324	0.219	86.3%	99.5%	116.9%	126.9%	137.0%	147.9%
BC-Alberta 6,1	0.096	0.278	0.322	0.242	0.178	0.160	0.405	23.7%	68.6%	79.5%	59.8%	44.0%	39.5%
Alberta-W CAN 5,2	0.741	1.021	1.208	1.310	1.477	1.696	1.071	69.2%	95.3%	112.8%	122.3%	137.9%	158.4%
Alberta-Sask 7,2	2.046	2.469	2.741	2.892	3.052	3.164	2.332	87.7%	105.9%	117.5%	124.0%	130.9%	135.7%
Sask-W CAN 4,3	0.155	0.057	0.023	0.013	0.013	0.025	0.200	77.5%	28.5%	11.5%	6.5%	6.5%	12.5%
Sask-Ontario 5,3	1.712	1.965	2.160	2.286	2.424	2.550	1.800	95.1%	109.2%	120.0%	127.0%	134.7%	141.7%
Ontario-E CAN 7,9	0.218	0.329	0.370	0.402	0.444	0.500	0.438	49.8%	75.1%	84.5%	91.8%	101.4%	114.2%
Alberta-S Alberta 8,2	0.767	0.715	0.780	0.868	0.939	0.958	1.190	64.5%	60.1%	65.5%	72.9%	78.9%	80.5%
PGT-Stanfield 7,13	0.740	0.679	0.747	0.842	0.920	0.943	0.909	81.4%	74.7%	82.2%	92.6%	101.2%	103.7%
Mont Pwr-Montana 11,13	0.018	0.028	0.024	0.016	0.009	0.004	0.040	45.0%	70.0%	60.0%	40.0%	22.5%	10.0%
Detailed PGT Flows													
PGT-Stanfield 7,13	0.740	0.679	0.747	0.842	0.920	0.943	0.909	81.4%	74.7%	82.2%	92.6%	101.2%	103.7%
to PNW Demand 22,13	0.000	0.043	0.061	0.063	0.065	0.067	0.054	0.0%	79.6%	113.0%	116.7%	120.4%	124.1%
to Reno Lateral 15,13	0.138	0.091	0.091	0.093	0.106	0.106	0.198	69.7%	46.0%	46.0%	47.0%	53.5%	53.5%
PGT-Malin 21,13	0.590	0.568	0.632	0.734	0.796	0.825	0.657	89.8%	86.5%	96.2%	111.7%	121.2%	125.6%
BC-Washington 5,1	0.276	0.286	0.307	0.299	0.305	0.306	0.405	68.1%	70.6%	75.8%	73.8%	75.3%	75.6%
NWPL-Pac NW 10,13	0.271	0.281	0.302	0.294	0.300	0.301	0.399	67.9%	70.4%	75.7%	73.7%	75.2%	75.4%
Alberta-E Mont 6,2	0.525	0.989	1.030	1.068	1.099	1.097	0.800	65.6%	123.6%	128.8%	133.5%	137.4%	137.1%
N Border-WNC 17,13	0.378	0.387	0.415	0.463	0.502	0.499	0.800	47.3%	48.4%	51.9%	57.9%	62.8%	62.4%
N Border-ENC 17,13	0.138	0.575	0.588	0.576	0.567	0.568	0.492	28.0%	116.9%	119.5%	117.1%	115.2%	115.4%
Saskatchewan-W Minn 6,3	0.431	0.662	0.680	0.680	0.674	0.650	0.433	99.5%	152.9%	157.0%	157.0%	155.7%	150.1%
Gr Lake/Mwst-ENC 13,13	0.403	0.619	0.636	0.635	0.630	0.608	0.494	81.6%	125.3%	128.7%	128.5%	127.5%	123.1%
NY-Mid Atl 14,13	0.589	0.614	0.665	0.696	0.721	0.704	0.756	77.9%	81.2%	88.0%	92.1%	95.4%	93.1%
Vermont-NE 20,13	0.018	0.039	0.040	0.041	0.044	0.045	0.023	78.3%	169.6%	173.9%	178.3%	191.3%	195.7%
Sable Island - NE 4,5	0.000	0.000	0.054	0.111	0.122	0.147	0.146	0.0%	0.0%	37.0%	76.0%	83.6%	100.7%

APPENDIX G
MARGIN FORECASTS AND ALLOCATION FACTORS FOR CALIFORNIA UTILITIES

Forecasted Annual Margin Revenue Requirements

millions of 1995 dollars

	PG&E		SoCal Gas	SDG&E	
Year	**Margin**	**Backbone**	**Margin**	**Paid To SoCal**	**Margin**
1997	$1,210.4	$193.9	$1,245.7	$22.8	$220.0
1998	$1,206.0	$193.2	$1,256.7	$20.9	$221.7
1999	$1,196.2	$191.6	$1,254.4	$19.8	$221.5
2000	$1,187.2	$190.2	$1,260.8	$20.4	$223.8
2001	$1,178.3	$188.7	$1,266.4	$22.2	$226.9
2002	$1,169.5	$187.3	$1,264.2	$24.7	$230.3
2003	$1,225.3	$196.3	$1,269.8	$23.7	$229.9
2004	$1,215.0	$194.6	$1,241.6	$23.9	$230.1
2005	$1,148.8	$184.0	$1,258.3	$23.7	$229.2
2006	$1,142.5	$183.0	$1,228.9	$24.1	$228.7
2007	$1,137.6	$182.2	$1,236.5	$24.9	$228.3
2008	$1,121.3	$179.6	$1,226.5	$25.1	$227.1
2009	$1,127.1	$180.6	$1,230.5	$24.7	$225.0
2010	$1,119.8	$179.4	$1,224.0	$25.0	$223.6
2011	$1,114.2	$178.5	$1,214.8	$25.6	$223.3
2012	$1,108.6	$177.6	$1,224.7	$25.5	$222.2
2013	$1,103.2	$176.7	$1,219.2	$25.9	$221.7
2014	$1,099.6	$176.1	$1,228.1	$26.3	$221.3
2015	$1,094.1	$175.3	$1,222.1	$25.9	$220.2
2016	$1,094.1	$175.3	$1,220.8	$26.2	$219.6
2017	$1,094.1	$175.3	$1,221.6	$26.4	$219.2

Notes:

PG&E margin does not include backbone
SoCal Gas margin does not include SDG&E transport payments
SDG&E margin includes transport payments made to SoCal Gas
These margin revenue needs were used for the Base, Low and High cases.

PG&E
Margin Allocation Factors
Base Case

	Core Allocation Factors			Noncore Allocation Factors				
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**
1997	0.6495	0.2163	0.0248	0.0257	0.0287	0.0040	0.0182	0.0329
1998	0.6468	0.2168	0.0254	0.0253	0.0289	0.0071	0.0188	0.0310
1999	0.6430	0.2178	0.0259	0.0249	0.0289	0.0101	0.0185	0.0309
2000	0.6367	0.2178	0.0265	0.0251	0.0299	0.0109	0.0202	0.0330
2001	0.6343	0.2198	0.0268	0.0250	0.0301	0.0116	0.0200	0.0324
2002	0.6312	0.2214	0.0268	0.0251	0.0301	0.0123	0.0207	0.0323
2003	0.6279	0.2220	0.0269	0.0251	0.0304	0.0131	0.0201	0.0345
2004	0.6278	0.2234	0.0271	0.0250	0.0304	0.0137	0.0202	0.0323
2005	0.6259	0.2237	0.0271	0.0250	0.0304	0.0143	0.0209	0.0327
2006	0.6208	0.2228	0.0270	0.0252	0.0307	0.0149	0.0215	0.0371
2007	0.6217	0.2232	0.0272	0.0250	0.0308	0.0153	0.0208	0.0359
2008	0.6199	0.2226	0.0273	0.0250	0.0310	0.0159	0.0209	0.0374
2009	0.6180	0.2217	0.0274	0.0250	0.0312	0.0164	0.0213	0.0391
2010	0.6189	0.2217	0.0274	0.0249	0.0312	0.0164	0.0219	0.0376
2011	0.6193	0.2213	0.0275	0.0248	0.0312	0.0165	0.0220	0.0373
2012	0.6176	0.2199	0.0275	0.0248	0.0315	0.0167	0.0223	0.0398
2013	0.6196	0.2198	0.0276	0.0246	0.0315	0.0167	0.0220	0.0381
2014	0.6197	0.2191	0.0276	0.0246	0.0315	0.0168	0.0220	0.0388
2015	0.6194	0.2182	0.0275	0.0246	0.0315	0.0167	0.0223	0.0398
2016	0.6199	0.2175	0.0274	0.0245	0.0315	0.0166	0.0224	0.0402
2017	0.6211	0.2163	0.0273	0.0245	0.0314	0.0165	0.0224	0.0405

Based on: PG&E, Revised BCAP Prepared Testimony and Workpapers(A 97-03-002), Aug. 27, 1997
EOR Revised BCAP Workpapers, Vol II, Page 6-26R.
CEC natural gas demand forecast.

SoCal Gas
Margin Allocation Factors
Base Case

	Core Allocation Factors			Noncore Allocation Factors					
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**SDG&E**
1997	0.7407	0.1115	0.0288	0.0071	0.0406	0.0197	0.0106	0.0235	0.0174
1998	0.7365	0.1141	0.0295	0.0073	0.0423	0.0163	0.0107	0.0252	0.0180
1999	0.7322	0.1166	0.0302	0.0076	0.0444	0.0129	0.0109	0.0281	0.0171
2000	0.7253	0.1185	0.0311	0.0077	0.0460	0.0123	0.0110	0.0307	0.0175
2001	0.7170	0.1240	0.0313	0.0078	0.0464	0.0116	0.0108	0.0323	0.0189
2002	0.7093	0.1277	0.0310	0.0079	0.0466	0.0110	0.0108	0.0346	0.0210
2003	0.7079	0.1318	0.0313	0.0079	0.0467	0.0102	0.0107	0.0333	0.0201
2004	0.7009	0.1343	0.0313	0.0081	0.0473	0.0097	0.0108	0.0368	0.0208
2005	0.7009	0.1373	0.0314	0.0081	0.0470	0.0094	0.0107	0.0349	0.0203
2006	0.6960	0.1392	0.0312	0.0082	0.0472	0.0092	0.0107	0.0372	0.0212
2007	0.6927	0.1428	0.0316	0.0081	0.0469	0.0088	0.0104	0.0369	0.0217
2008	0.6896	0.1440	0.0316	0.0082	0.0473	0.0086	0.0104	0.0383	0.0220
2009	0.6904	0.1403	0.0312	0.0085	0.0488	0.0086	0.0106	0.0398	0.0219
2010	0.6886	0.1420	0.0314	0.0085	0.0487	0.0085	0.0105	0.0398	0.0219
2011	0.6848	0.1430	0.0314	0.0085	0.0488	0.0085	0.0104	0.0419	0.0226
2012	0.6834	0.1443	0.0314	0.0086	0.0490	0.0084	0.0103	0.0420	0.0227
2013	0.6799	0.1449	0.0313	0.0086	0.0493	0.0083	0.0103	0.0443	0.0231
2014	0.6786	0.1458	0.0314	0.0087	0.0492	0.0083	0.0102	0.0446	0.0234
2015	0.6772	0.1464	0.0314	0.0087	0.0491	0.0083	0.0101	0.0455	0.0232
2016	0.6755	0.1470	0.0314	0.0088	0.0489	0.0083	0.0101	0.0467	0.0234
2017	0.6738	0.1476	0.0312	0.0089	0.0488	0.0083	0.0100	0.0478	0.0236

Based on: SoCal Gas Advice No. 2640, dated July 23, 1997, pages 29356-G thru 29359-G.
EOR from SoCal Advice No. 2609, page 28897-G.
CPUC Decision 97-04-82, dated, Apr. 23, 1997, Appendix D, pages 5 and 6.
CEC natural gas demand forecast.

SDG&E
Margin Allocation Factors
Base Case

	Core Allocation Factors			Noncore Allocation Factors				
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**
1997	0.5678	0.2479	0.0248	0.0291	0.0086	0.0000	0.0352	0.0865
1998	0.5596	0.2478	0.0252	0.0286	0.0086	0.0000	0.0489	0.0813
1999	0.5660	0.2541	0.0264	0.0287	0.0089	0.0000	0.0482	0.0677
2000	0.5600	0.2538	0.0272	0.0287	0.0092	0.0000	0.0477	0.0734
2001	0.5570	0.2569	0.0278	0.0287	0.0094	0.0000	0.0470	0.0731
2002	0.5219	0.2438	0.0264	0.0285	0.0094	0.0000	0.0461	0.1238
2003	0.5285	0.2495	0.0273	0.0286	0.0096	0.0000	0.0458	0.1106
2004	0.5215	0.2487	0.0277	0.0282	0.0097	0.0000	0.0452	0.1191
2005	0.5249	0.2524	0.0284	0.0282	0.0098	0.0000	0.0447	0.1116
2006	0.5159	0.2496	0.0284	0.0281	0.0099	0.0000	0.0440	0.1240
2007	0.5096	0.2477	0.0286	0.0279	0.0100	0.0000	0.0433	0.1328
2008	0.5056	0.2466	0.0289	0.0278	0.0102	0.0000	0.0427	0.1383
2009	0.5116	0.2502	0.0297	0.0278	0.0103	0.0000	0.0424	0.1281
2010	0.5117	0.2508	0.0300	0.0276	0.0103	0.0000	0.0419	0.1277
2011	0.5059	0.2485	0.0300	0.0272	0.0103	0.0000	0.0413	0.1367
2012	0.5060	0.2486	0.0305	0.0270	0.0104	0.0000	0.0408	0.1368
2013	0.5031	0.2471	0.0306	0.0267	0.0104	0.0000	0.0402	0.1419
2014	0.5024	0.2466	0.0308	0.0265	0.0104	0.0000	0.0398	0.1436
2015	0.5050	0.2478	0.0311	0.0262	0.0103	0.0000	0.0394	0.1401
2016	0.5043	0.2472	0.0311	0.0260	0.0103	0.0000	0.0390	0.1422
2017	0.5043	0.2461	0.0311	0.0257	0.0102	0.0000	0.0385	0.1440

Based on: SoCal Gas/SDG&E BCAP Decision 97-04-082 issued on Apr 23, 1997.
CEC natural gas demand forecast.

APPENDIX H
BASECASE NATURAL GAS PRICE FORECAST

At the California Energy Commission Business meeting, held on March 18, 1998, the Basecase natural gas price forecast was adopted as the Commission’s natural gas price forecast for the ***Fuels Report***. It represent the most likely long term natural gas price forecast. The Basecase forecast was adopted in constant 1995 $/mcf. In these tables, the natural gas price forecast for electricity generation has been converted to current $/mmbtu.

Table H-1

PG&E Service Area
Base Case
End-use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.42	6.33	5.59	3.63	3.94	2.93	3.65	3.65	4.40
1991	6.44	6.44	5.64	2.99	3.14	3.47	3.15	3.15	4.25
1992	6.20	6.77	5.04	2.89	2.31	2.72	2.87	2.87	4.51
1993	5.92	6.28	4.97	3.10	2.30	2.43	3.10	3.10	3.69
1994	6.11	6.32	4.65	3.02	2.06	2.05	2.32	2.32	3.62
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1996	6.74	6.77	4.68	2.99	2.32	2.05	2.36	2.36	4.07
1997	7.13	7.12	4.69	3.45	2.80	2.58	2.66	2.66	4.27
1998	6.78	7.32	4.22	3.46	2.46	2.38	2.41	2.41	4.00
1999	6.34	6.33	3.47	3.13	2.16	2.08	2.10	2.10	3.57
2000	6.09	6.08	3.42	3.01	2.05	1.98	1.99	1.99	3.36
2001	5.91	5.90	3.41	3.02	2.08	2.02	2.02	2.02	3.33
2002	5.73	5.72	3.41	3.03	2.10	2.06	2.05	2.05	3.28
2003	5.71	5.70	3.42	3.06	2.14	2.10	2.09	2.09	3.27
2004	5.70	5.69	3.43	3.07	2.18	2.13	2.12	2.12	3.30
2005	5.67	5.67	3.44	3.10	2.21	2.17	2.16	2.16	3.31
2006	5.63	5.63	3.44	3.13	2.24	2.20	2.19	2.19	3.27
2007	5.63	5.62	3.45	3.14	2.27	2.24	2.22	2.22	3.30
2008	5.58	5.57	3.45	3.15	2.30	2.27	2.25	2.25	3.29
2009	5.59	5.59	3.47	3.18	2.33	2.30	2.28	2.28	3.30
2010	5.59	5.59	3.49	3.21	2.37	2.34	2.31	2.31	3.33
2011	5.59	5.58	3.52	3.24	2.41	2.38	2.35	2.35	3.36
2012	5.56	5.56	3.53	3.28	2.46	2.43	2.40	2.40	3.37
2013	5.56	5.56	3.54	3.32	2.50	2.47	2.45	2.45	3.41
2014	5.56	5.56	3.56	3.36	2.55	2.52	2.49	2.49	3.44
2015	5.55	5.55	3.58	3.39	2.59	2.56	2.54	2.54	3.46
2016	5.57	5.57	3.61	3.43	2.63	2.60	2.58	2.58	3.49
2017	5.57	5.58	3.63	3.46	2.68	2.64	2.62	2.62	3.52

Note:

- 1990 - 1995 prices are historical for residential, commercial, industrial, and TEOR
- Prices between 1995 and 1997 are interpolated.
- 1990 - 1996 prices are historical for cogeneration and EG.
- 1997 and later years are forecasted.

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7.
- 1997 margin based on PG&E Advice No. 1978-G, November 15, 1998.
- Remaining years margin based on PG&E Revised BCAP Application No. 97-03-002 and associated work papers (Aug. 18 and 27, 1997).
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- PG&E Margin: Includes base margin, access charges, portion of the backbone costs, local transmission and core storage.
- PG&E Backbone: Weighted average transmission charge to transport natural gas on Line 300, phased in Line 400/401, and incremental Line 401.
- Regulatory: Instate charge to recover customer class charges, including balancing accounts, social, environmental, and other regulatory accounts.

Adopted March 18, 1998

Table H-2

PG&E Service Area
Base Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							6.42
1991							6.44
1992							6.20
1993							5.92
1994							6.11
1995							6.35
1996							6.74
1997	1.72	0.46	0.04	4.43	0.00	0.49	7.13
1998	1.47	0.46	0.04	3.95	0.12	0.74	6.78
1999	1.24	0.47	0.04	3.88	0.12	0.58	6.34
2000	1.27	0.47	0.00	3.81	0.12	0.43	6.09
2001	1.31	0.47	0.00	3.75	0.12	0.27	5.91
2002	1.34	0.47	0.00	3.70	0.12	0.12	5.73
2003	1.37	0.47	0.00	3.64	0.12	0.12	5.71
2004	1.39	0.46	0.00	3.61	0.12	0.12	5.70
2005	1.42	0.46	0.00	3.56	0.12	0.12	5.67
2006	1.44	0.46	0.00	3.49	0.12	0.12	5.63
2007	1.47	0.46	0.00	3.46	0.12	0.12	5.63
2008	1.49	0.46	0.00	3.38	0.12	0.12	5.58
2009	1.52	0.46	0.00	3.37	0.12	0.12	5.59
2010	1.56	0.46	0.00	3.33	0.12	0.12	5.59
2011	1.60	0.46	0.00	3.29	0.12	0.12	5.59
2012	1.63	0.46	0.00	3.24	0.12	0.12	5.56
2013	1.65	0.46	0.00	3.21	0.12	0.12	5.56
2014	1.68	0.47	0.00	3.17	0.12	0.12	5.56
2015	1.72	0.47	0.00	3.13	0.12	0.12	5.55
2016	1.76	0.47	0.00	3.11	0.12	0.12	5.57
2017	1.79	0.47	0.00	3.08	0.12	0.12	5.57

Adopted March 18, 1998

Table H-2 (continued)

PG&E Service Area
Base Case
Commercial Core Price Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							6.33
1991							6.44
1992							6.77
1993							6.28
1994							6.32
1995							6.41
1996							6.77
1997	1.72	0.46	0.04	4.43	0.00	0.48	7.12
1998	1.47	0.46	0.04	4.43	0.12	0.80	7.32
1999	1.24	0.47	0.04	3.81	0.12	0.64	6.33
2000	1.27	0.47	0.00	3.74	0.12	0.49	6.08
2001	1.31	0.47	0.00	3.68	0.12	0.33	5.90
2002	1.34	0.47	0.00	3.63	0.12	0.18	5.72
2003	1.37	0.47	0.00	3.58	0.12	0.18	5.70
2004	1.39	0.46	0.00	3.54	0.12	0.18	5.69
2005	1.42	0.46	0.00	3.49	0.12	0.18	5.67
2006	1.44	0.46	0.00	3.43	0.12	0.18	5.63
2007	1.47	0.46	0.00	3.40	0.12	0.18	5.62
2008	1.49	0.46	0.00	3.32	0.12	0.18	5.57
2009	1.52	0.46	0.00	3.31	0.12	0.18	5.59
2010	1.56	0.46	0.00	3.27	0.12	0.18	5.59
2011	1.60	0.46	0.00	3.23	0.12	0.18	5.58
2012	1.63	0.46	0.00	3.18	0.12	0.18	5.56
2013	1.65	0.46	0.00	3.15	0.12	0.18	5.56
2014	1.68	0.47	0.00	3.12	0.12	0.18	5.56
2015	1.72	0.47	0.00	3.07	0.12	0.18	5.55
2016	1.76	0.47	0.00	3.05	0.12	0.18	5.57
2017	1.79	0.47	0.00	3.02	0.12	0.18	5.58

Adopted March 18, 1998

Table H-2 (continued)

PG&E Service Area
Base Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							5.59
1991							5.64
1992							5.04
1993							4.97
1994							4.65
1995							4.67
1996							4.68
1997	1.72	0.46	0.04	2.40	0.00	0.08	4.69
1998	1.47	0.46	0.04	2.00	0.12	0.12	4.22
1999	1.24	0.47	0.04	1.48	0.12	0.11	3.47
2000	1.27	0.47	0.00	1.45	0.12	0.10	3.42
2001	1.31	0.47	0.00	1.43	0.12	0.09	3.41
2002	1.34	0.47	0.00	1.41	0.12	0.08	3.41
2003	1.37	0.47	0.00	1.39	0.12	0.08	3.42
2004	1.39	0.46	0.00	1.38	0.12	0.08	3.43
2005	1.42	0.46	0.00	1.36	0.12	0.08	3.44
2006	1.44	0.46	0.00	1.33	0.12	0.08	3.44
2007	1.47	0.46	0.00	1.32	0.12	0.08	3.45
2008	1.49	0.46	0.00	1.29	0.12	0.08	3.45
2009	1.52	0.46	0.00	1.29	0.12	0.08	3.47
2010	1.56	0.46	0.00	1.27	0.12	0.08	3.49
2011	1.60	0.46	0.00	1.26	0.12	0.08	3.52
2012	1.63	0.46	0.00	1.24	0.12	0.08	3.53
2013	1.65	0.46	0.00	1.23	0.12	0.08	3.54
2014	1.68	0.47	0.00	1.21	0.12	0.08	3.56
2015	1.72	0.47	0.00	1.20	0.12	0.08	3.58
2016	1.76	0.47	0.00	1.19	0.12	0.08	3.61
2017	1.79	0.47	0.00	1.18	0.12	0.08	3.63

Adopted March 18, 1998

Table H-3

PG&E Service Area
Base Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.63
1991							2.99
1992							2.89
1993							3.10
1994							3.02
1995							2.52
1996							2.99
1997	1.79	0.20	0.10	1.28	0.00	0.08	3.45
1998	1.53	0.27	0.14	1.20	0.18	0.14	3.46
1999	1.25	0.26	0.14	1.17	0.18	0.13	3.13
2000	1.29	0.27	0.00	1.16	0.18	0.12	3.01
2001	1.32	0.28	0.00	1.13	0.17	0.11	3.02
2002	1.36	0.29	0.00	1.12	0.17	0.10	3.03
2003	1.39	0.30	0.00	1.10	0.16	0.10	3.06
2004	1.41	0.33	0.00	1.08	0.16	0.10	3.07
2005	1.43	0.35	0.00	1.07	0.16	0.10	3.10
2006	1.45	0.36	0.00	1.06	0.15	0.10	3.13
2007	1.48	0.38	0.00	1.05	0.15	0.10	3.14
2008	1.50	0.39	0.00	1.03	0.14	0.10	3.15
2009	1.52	0.40	0.00	1.03	0.14	0.10	3.18
2010	1.60	0.37	0.00	1.01	0.13	0.10	3.21
2011	1.63	0.38	0.00	1.00	0.13	0.10	3.24
2012	1.66	0.41	0.00	0.99	0.13	0.10	3.28
2013	1.69	0.43	0.00	0.98	0.13	0.10	3.32
2014	1.72	0.44	0.00	0.97	0.13	0.10	3.36
2015	1.76	0.45	0.00	0.96	0.13	0.10	3.39
2016	1.79	0.46	0.00	0.95	0.13	0.10	3.43
2017	1.83	0.46	0.00	0.95	0.13	0.10	3.46

Adopted March 18, 1998

Table H-3 (continued)

PG&E Service Area
Base Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.94
1991							3.14
1992							2.31
1993							2.30
1994							2.06
1995							1.85
1996							2.32
1997	1.79	0.20	0.10	0.63	0.00	0.08	2.80
1998	1.53	0.27	0.14	0.22	0.18	0.12	2.46
1999	1.25	0.26	0.14	0.21	0.18	0.11	2.16
2000	1.29	0.27	0.00	0.21	0.18	0.10	2.05
2001	1.32	0.28	0.00	0.21	0.17	0.09	2.08
2002	1.36	0.29	0.00	0.20	0.17	0.08	2.10
2003	1.39	0.30	0.00	0.20	0.16	0.08	2.14
2004	1.41	0.33	0.00	0.20	0.16	0.08	2.18
2005	1.43	0.35	0.00	0.20	0.16	0.08	2.21
2006	1.45	0.36	0.00	0.19	0.15	0.08	2.24
2007	1.48	0.38	0.00	0.19	0.15	0.08	2.27
2008	1.50	0.39	0.00	0.19	0.14	0.08	2.30
2009	1.52	0.40	0.00	0.19	0.14	0.08	2.33
2010	1.60	0.37	0.00	0.19	0.13	0.08	2.37
2011	1.63	0.38	0.00	0.18	0.13	0.08	2.41
2012	1.66	0.41	0.00	0.18	0.13	0.08	2.46
2013	1.69	0.43	0.00	0.18	0.13	0.08	2.50
2014	1.72	0.44	0.00	0.18	0.13	0.08	2.55
2015	1.76	0.45	0.00	0.18	0.13	0.08	2.59
2016	1.79	0.46	0.00	0.17	0.13	0.08	2.63
2017	1.83	0.46	0.00	0.17	0.13	0.08	2.68

Adopted March 18, 1998

Table H-3 (continued)

PG&E Service Area
Base Case
TEOR Noncore Natural Gas Price

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							2.93
1991							3.47
1992							2.72
1993							2.43
1994							2.05
1995							1.52
1996							2.05
1997	1.79	0.20	0.10	0.49	0.00	0.00	2.58
1998	1.53	0.27	0.14	0.44	0.00	0.00	2.38
1999	1.25	0.26	0.14	0.43	0.00	0.00	2.08
2000	1.29	0.27	0.00	0.42	0.00	0.00	1.98
2001	1.32	0.28	0.00	0.42	0.00	0.00	2.02
2002	1.36	0.29	0.00	0.41	0.00	0.00	2.06
2003	1.39	0.30	0.00	0.40	0.00	0.00	2.10
2004	1.41	0.33	0.00	0.40	0.00	0.00	2.13
2005	1.43	0.35	0.00	0.39	0.00	0.00	2.17
2006	1.45	0.36	0.00	0.39	0.00	0.00	2.20
2007	1.48	0.38	0.00	0.38	0.00	0.00	2.24
2008	1.50	0.39	0.00	0.38	0.00	0.00	2.27
2009	1.52	0.40	0.00	0.38	0.00	0.00	2.30
2010	1.60	0.37	0.00	0.37	0.00	0.00	2.34
2011	1.63	0.38	0.00	0.37	0.00	0.00	2.38
2012	1.66	0.41	0.00	0.36	0.00	0.00	2.43
2013	1.69	0.43	0.00	0.36	0.00	0.00	2.47
2014	1.72	0.44	0.00	0.36	0.00	0.00	2.52
2015	1.76	0.45	0.00	0.35	0.00	0.00	2.56
2016	1.79	0.46	0.00	0.35	0.00	0.00	2.60
2017	1.83	0.46	0.00	0.35	0.00	0.00	2.64

Adopted March 18, 1998

Table H-4

PG&E Service Area

Base Case

Cogen Noncore Natural Gas Price

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	1.82	0.22	0.10	0.49	0.00	0.03	2.66
1998	1.55	0.28	0.14	0.20	0.18	0.07	2.41
1999	1.26	0.27	0.14	0.19	0.18	0.06	2.10
2000	1.30	0.28	0.00	0.19	0.17	0.06	1.99
2001	1.33	0.29	0.00	0.18	0.17	0.05	2.02
2002	1.37	0.29	0.00	0.18	0.17	0.04	2.05
2003	1.40	0.31	0.00	0.18	0.16	0.04	2.09
2004	1.42	0.33	0.00	0.18	0.16	0.04	2.12
2005	1.44	0.35	0.00	0.17	0.16	0.04	2.16
2006	1.46	0.36	0.00	0.17	0.15	0.04	2.19
2007	1.49	0.37	0.00	0.17	0.15	0.04	2.22
2008	1.51	0.38	0.00	0.17	0.14	0.04	2.25
2009	1.54	0.40	0.00	0.17	0.14	0.04	2.28
2010	1.60	0.37	0.00	0.16	0.13	0.04	2.31
2011	1.64	0.38	0.00	0.16	0.13	0.04	2.35
2012	1.67	0.40	0.00	0.16	0.13	0.04	2.40
2013	1.70	0.42	0.00	0.16	0.13	0.04	2.45
2014	1.73	0.44	0.00	0.16	0.13	0.04	2.49
2015	1.77	0.44	0.00	0.16	0.13	0.04	2.54
2016	1.80	0.45	0.00	0.15	0.13	0.04	2.58
2017	1.84	0.46	0.00	0.15	0.13	0.04	2.62

Adopted March 18, 1998

Table H-4 (continued)

PG&E Service
Base Case
Electricity Generation Noncore Price

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	1.82	0.22	0.10	0.49	0.00	0.03	2.66
1998	1.55	0.28	0.14	0.20	0.18	0.07	2.41
1999	1.26	0.27	0.14	0.19	0.18	0.06	2.10
2000	1.30	0.28	0.00	0.19	0.17	0.06	1.99
2001	1.33	0.29	0.00	0.18	0.17	0.05	2.02
2002	1.37	0.29	0.00	0.18	0.17	0.04	2.05
2003	1.40	0.31	0.00	0.18	0.16	0.04	2.09
2004	1.42	0.33	0.00	0.18	0.16	0.04	2.12
2005	1.44	0.35	0.00	0.17	0.16	0.04	2.16
2006	1.46	0.36	0.00	0.17	0.15	0.04	2.19
2007	1.49	0.37	0.00	0.17	0.15	0.04	2.22
2008	1.51	0.38	0.00	0.17	0.14	0.04	2.25
2009	1.54	0.40	0.00	0.17	0.14	0.04	2.28
2010	1.60	0.37	0.00	0.16	0.13	0.04	2.31
2011	1.64	0.38	0.00	0.16	0.13	0.04	2.35
2012	1.67	0.40	0.00	0.16	0.13	0.04	2.40
2013	1.70	0.42	0.00	0.16	0.13	0.04	2.45
2014	1.73	0.44	0.00	0.16	0.13	0.04	2.49
2015	1.77	0.44	0.00	0.16	0.13	0.04	2.54
2016	1.80	0.45	0.00	0.15	0.13	0.04	2.58
2017	1.84	0.46	0.00	0.15	0.13	0.04	2.62

Adopted March 18, 1998

Table H-5

PG&E Service
Base Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

	Electricity Generation			
		Transportation		Total
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**
1990				3.55
1991				3.08
1992				2.80
1993				3.02
1994				2.26
1995				2.21
1996				2.32
1997	1.79	0.21	0.61	2.61
1998	1.52	0.27	0.57	2.36
1999	1.24	0.26	0.56	2.06
2000	1.27	0.27	0.41	1.95
2001	1.31	0.28	0.39	1.98
2002	1.34	0.29	0.38	2.01
2003	1.37	0.30	0.38	2.05
2004	1.39	0.32	0.37	2.08
2005	1.41	0.34	0.36	2.12
2006	1.43	0.35	0.36	2.15
2007	1.46	0.37	0.35	2.17
2008	1.48	0.38	0.34	2.20
2009	1.51	0.39	0.34	2.23
2010	1.57	0.36	0.33	2.27
2011	1.61	0.37	0.33	2.31
2012	1.64	0.39	0.32	2.35
2013	1.67	0.41	0.32	2.40
2014	1.70	0.43	0.32	2.45
2015	1.73	0.43	0.32	2.49
2016	1.77	0.44	0.32	2.53
2017	1.80	0.45	0.32	2.57

Adopted March 18, 1998

Table H-5 (continued)

PG&E Service Area
Base Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Electricity Generation				Cogen
		Transportation		Total	Gas
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990				3.09	3.09
1991				2.79	2.79
1992				2.61	2.61
1993				2.88	2.88
1994				2.20	2.20
1995				2.21	2.21
1996				2.37	2.37
1997	1.86	0.22	0.63	2.71	2.71
1998	1.61	0.29	0.61	2.51	2.51
1999	1.35	0.29	0.61	2.24	2.24
2000	1.42	0.30	0.46	2.19	2.19
2001	1.51	0.32	0.45	2.28	2.28
2002	1.59	0.34	0.45	2.38	2.38
2003	1.67	0.37	0.46	2.50	2.50
2004	1.75	0.40	0.46	2.62	2.62
2005	1.84	0.44	0.47	2.75	2.75
2006	1.93	0.48	0.48	2.89	2.89
2007	2.03	0.51	0.49	3.03	3.03
2008	2.14	0.54	0.49	3.18	3.18
2009	2.25	0.58	0.50	3.34	3.34
2010	2.44	0.56	0.51	3.51	3.51
2011	2.58	0.60	0.52	3.70	3.70
2012	2.72	0.65	0.54	3.91	3.91
2013	2.87	0.71	0.56	4.13	4.13
2014	3.02	0.76	0.57	4.36	4.36
2015	3.20	0.80	0.59	4.59	4.59
2016	3.38	0.84	0.61	4.83	4.83
2017	3.57	0.89	0.63	5.09	5.09

Adopted March 18, 1998

Table H-6

SoCal Gas Service Area
Base Case
End-use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.40	6.76	5.99	4.28	3.79	3.37	3.67	3.67	4.75
1991	6.99	7.34	7.34	3.91	3.64	2.86	3.22	3.22	4.72
1992	6.82	7.66	6.40	5.00	3.75	2.82	3.13	3.13	4.78
1993	7.24	7.65	6.71	4.98	3.73	3.16	3.14	3.14	5.01
1994	7.03	6.81	6.59	3.32	2.48	2.48	2.65	2.65	4.60
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1996	6.81	5.87	5.06	2.73	2.68	2.43	2.94	2.94	4.53
1997	6.93	5.19	4.26	3.07	3.06	2.85	2.87	2.87	4.42
1998	6.42	4.68	3.75	2.75	2.74	2.53	2.52	2.52	4.00
1999	6.02	4.30	3.38	2.39	2.39	2.22	2.13	2.13	3.60
2000	5.91	4.20	3.28	2.27	2.26	2.28	1.99	1.99	3.44
2001	5.90	4.21	3.30	2.31	2.31	2.33	2.04	2.04	3.45
2002	5.87	4.21	3.32	2.36	2.35	2.38	2.08	2.08	3.44
2003	5.91	4.24	3.36	2.41	2.41	2.43	2.14	2.14	3.50
2004	5.79	4.19	3.34	2.46	2.46	2.49	2.19	2.19	3.46
2005	5.84	4.22	3.37	2.51	2.51	2.53	2.24	2.24	3.53
2006	5.73	4.17	3.35	2.54	2.54	2.57	2.28	2.28	3.49
2007	5.71	4.17	3.36	2.59	2.58	2.62	2.33	2.33	3.52
2008	5.69	4.18	3.38	2.65	2.65	2.68	2.40	2.40	3.54
2009	5.79	4.25	3.44	2.70	2.70	2.73	2.44	2.44	3.59
2010	5.78	4.26	3.46	2.70	2.69	2.73	2.44	2.44	3.59
2011	5.76	4.27	3.49	2.75	2.74	2.78	2.49	2.49	3.60
2012	5.80	4.32	3.54	2.80	2.79	2.83	2.54	2.54	3.64
2013	5.80	4.34	3.57	2.84	2.84	2.87	2.59	2.59	3.66
2014	5.84	4.38	3.61	2.89	2.89	2.92	2.64	2.64	3.70
2015	5.84	4.40	3.64	2.93	2.93	2.96	2.68	2.68	3.72
2016	5.84	4.42	3.68	2.98	2.97	3.00	2.73	2.73	3.75
2017	5.86	4.45	3.71	3.02	3.01	3.04	2.77	2.77	3.78

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7; 1996 prices are interpolated.
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- SoCal Gas Margin: Distribution and administration costs associated with running the SoCal Gas pipeline system.
- PITCO/POPCO: Global settlement associated with PITCO and POPCO long term supply contracts.
- Regulatory: Includes balancing accounts, social, environmental, and other regulatory accounts.

Adopted March 18, 1998

Table H-7

SoCal Gas Service Area
Base Case
Residential Core Price Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.40
1991							6.99
1992							6.82
1993							7.24
1994							7.03
1995							6.69
1996							6.81
1997	2.15	0.54	0.03	3.83	0.12	0.26	6.93
1998	1.80	0.38	0.03	3.83	0.12	0.26	6.42
1999	1.45	0.37	0.03	3.79	0.12	0.26	6.02
2000	1.49	0.37	0.03	3.76	0.00	0.26	5.91
2001	1.53	0.36	0.02	3.72	0.00	0.26	5.90
2002	1.58	0.36	0.02	3.66	0.00	0.26	5.87
2003	1.62	0.35	0.02	3.65	0.00	0.26	5.91
2004	1.65	0.35	0.01	3.52	0.00	0.26	5.79
2005	1.68	0.35	0.01	3.55	0.00	0.26	5.84
2006	1.71	0.34	0.01	3.42	0.00	0.26	5.73
2007	1.75	0.32	0.00	3.38	0.00	0.26	5.71
2008	1.78	0.34	0.00	3.31	0.00	0.26	5.69
2009	1.81	0.35	0.00	3.37	0.00	0.26	5.79
2010	1.86	0.34	0.00	3.32	0.00	0.26	5.78
2011	1.90	0.34	0.00	3.25	0.00	0.26	5.76
2012	1.95	0.35	0.00	3.25	0.00	0.26	5.80
2013	1.99	0.35	0.00	3.19	0.00	0.26	5.80
2014	2.04	0.35	0.00	3.19	0.00	0.26	5.84
2015	2.08	0.36	0.00	3.14	0.00	0.26	5.84
2016	2.12	0.36	0.00	3.11	0.00	0.26	5.84
2017	2.16	0.36	0.00	3.08	0.00	0.26	5.86

Adopted March 18, 1998

Table H-7 (continued)

SoCal Gas Service Area
Base Case
Commercial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.76
1991							7.34
1992							7.66
1993							7.65
1994							6.81
1995							6.55
1996							5.87
1997	2.15	0.54	0.03	2.14	0.12	0.21	5.19
1998	1.80	0.38	0.03	2.14	0.12	0.21	4.68
1999	1.45	0.37	0.03	2.12	0.12	0.21	4.30
2000	1.49	0.37	0.03	2.10	0.00	0.21	4.20
2001	1.53	0.36	0.02	2.08	0.00	0.21	4.21
2002	1.58	0.36	0.02	2.05	0.00	0.21	4.21
2003	1.62	0.35	0.02	2.04	0.00	0.21	4.24
2004	1.65	0.35	0.01	1.97	0.00	0.21	4.19
2005	1.68	0.35	0.01	1.98	0.00	0.21	4.22
2006	1.71	0.34	0.01	1.91	0.00	0.21	4.17
2007	1.75	0.32	0.00	1.89	0.00	0.21	4.17
2008	1.78	0.34	0.00	1.85	0.00	0.21	4.18
2009	1.81	0.35	0.00	1.88	0.00	0.21	4.25
2010	1.86	0.34	0.00	1.86	0.00	0.21	4.26
2011	1.90	0.34	0.00	1.82	0.00	0.21	4.27
2012	1.95	0.35	0.00	1.82	0.00	0.21	4.32
2013	1.99	0.35	0.00	1.79	0.00	0.21	4.34
2014	2.04	0.35	0.00	1.78	0.00	0.21	4.38
2015	2.08	0.36	0.00	1.76	0.00	0.21	4.40
2016	2.12	0.36	0.00	1.74	0.00	0.21	4.42
2017	2.16	0.36	0.00	1.72	0.00	0.21	4.45

Adopted March 18, 1998

Table H-7 (continued)

SoCal Gas Service Area
Base Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							5.99
1991							7.34
1992							6.40
1993							6.71
1994							6.59
1995							5.85
1996							5.06
1997	2.15	0.54	0.03	1.16	0.12	0.25	4.26
1998	1.80	0.38	0.03	1.16	0.12	0.25	3.75
1999	1.45	0.37	0.03	1.15	0.12	0.25	3.38
2000	1.49	0.37	0.03	1.14	0.00	0.25	3.28
2001	1.53	0.36	0.02	1.13	0.00	0.25	3.30
2002	1.58	0.36	0.02	1.11	0.00	0.25	3.32
2003	1.62	0.35	0.02	1.11	0.00	0.25	3.36
2004	1.65	0.35	0.01	1.07	0.00	0.25	3.34
2005	1.68	0.35	0.01	1.08	0.00	0.25	3.37
2006	1.71	0.34	0.01	1.04	0.00	0.25	3.35
2007	1.75	0.32	0.00	1.03	0.00	0.25	3.36
2008	1.78	0.34	0.00	1.01	0.00	0.25	3.38
2009	1.81	0.35	0.00	1.02	0.00	0.25	3.44
2010	1.86	0.34	0.00	1.01	0.00	0.25	3.46
2011	1.90	0.34	0.00	0.99	0.00	0.25	3.49
2012	1.95	0.35	0.00	0.99	0.00	0.25	3.54
2013	1.99	0.35	0.00	0.97	0.00	0.25	3.57
2014	2.04	0.35	0.00	0.97	0.00	0.25	3.61
2015	2.08	0.36	0.00	0.95	0.00	0.25	3.64
2016	2.12	0.36	0.00	0.94	0.00	0.25	3.68
2017	2.16	0.36	0.00	0.94	0.00	0.25	3.71

Adopted March 18, 1998

Table H-8

SoCal Gas Service Area

Base Case

Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.28
1991							3.91
1992							5.00
1993							4.98
1994							3.32
1995							2.39
1996							2.73
1997	2.20	0.15	0.14	0.42	0.12	0.06	3.07
1998	1.81	0.20	0.13	0.42	0.12	0.06	2.75
1999	1.48	0.21	0.09	0.43	0.12	0.06	2.39
2000	1.52	0.23	0.03	0.43	0.00	0.06	2.27
2001	1.56	0.25	0.02	0.43	0.00	0.06	2.31
2002	1.60	0.26	0.02	0.42	0.00	0.06	2.36
2003	1.64	0.28	0.02	0.42	0.00	0.06	2.41
2004	1.67	0.32	0.01	0.41	0.00	0.06	2.46
2005	1.70	0.34	0.01	0.41	0.00	0.06	2.51
2006	1.73	0.36	0.01	0.40	0.00	0.06	2.54
2007	1.75	0.39	0.00	0.39	0.00	0.06	2.59
2008	1.78	0.43	0.00	0.39	0.00	0.06	2.65
2009	1.81	0.44	0.00	0.40	0.00	0.06	2.70
2010	1.85	0.40	0.00	0.39	0.00	0.06	2.70
2011	1.90	0.41	0.00	0.38	0.00	0.06	2.75
2012	1.94	0.42	0.00	0.38	0.00	0.06	2.80
2013	1.98	0.43	0.00	0.38	0.00	0.06	2.84
2014	2.02	0.44	0.00	0.38	0.00	0.06	2.89
2015	2.06	0.44	0.00	0.37	0.00	0.06	2.93
2016	2.10	0.45	0.00	0.37	0.00	0.06	2.98
2017	2.14	0.46	0.00	0.37	0.00	0.06	3.02

Adopted March 18, 1998

Table H-8 (continued)

SoCal Gas Service Area
Base Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.79
1991							3.64
1992							3.75
1993							3.73
1994							2.48
1995							2.29
1996							2.68
1997	2.20	0.15	0.14	0.41	0.12	0.06	3.06
1998	1.81	0.20	0.13	0.42	0.12	0.06	2.74
1999	1.48	0.21	0.09	0.43	0.12	0.06	2.39
2000	1.52	0.23	0.03	0.43	0.00	0.06	2.26
2001	1.56	0.25	0.02	0.42	0.00	0.06	2.31
2002	1.60	0.26	0.02	0.42	0.00	0.06	2.35
2003	1.64	0.28	0.02	0.42	0.00	0.06	2.41
2004	1.67	0.32	0.01	0.41	0.00	0.06	2.46
2005	1.70	0.34	0.01	0.41	0.00	0.06	2.51
2006	1.73	0.36	0.01	0.39	0.00	0.06	2.54
2007	1.75	0.39	0.00	0.39	0.00	0.06	2.58
2008	1.78	0.43	0.00	0.38	0.00	0.06	2.65
2009	1.81	0.44	0.00	0.39	0.00	0.06	2.70
2010	1.85	0.40	0.00	0.39	0.00	0.06	2.69
2011	1.90	0.41	0.00	0.38	0.00	0.06	2.74
2012	1.94	0.42	0.00	0.38	0.00	0.06	2.79
2013	1.98	0.43	0.00	0.38	0.00	0.06	2.84
2014	2.02	0.44	0.00	0.37	0.00	0.06	2.89
2015	2.06	0.44	0.00	0.37	0.00	0.06	2.93
2016	2.10	0.45	0.00	0.37	0.00	0.06	2.97
2017	2.14	0.46	0.00	0.37	0.00	0.06	3.01

Adopted March 18, 1998

Table H-8 (continued)

SoCal Gas Service Area
Base Case
TEOR Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.37
1991							2.86
1992							2.82
1993							3.16
1994							2.48
1995							2.01
1996							2.43
1997	2.20	0.15	0.00	0.51	0.00	0.00	2.85
1998	1.81	0.20	0.00	0.52	0.00	0.00	2.53
1999	1.48	0.21	0.00	0.52	0.00	0.00	2.22
2000	1.52	0.23	0.00	0.52	0.00	0.00	2.28
2001	1.56	0.25	0.00	0.52	0.00	0.00	2.33
2002	1.60	0.26	0.00	0.52	0.00	0.00	2.38
2003	1.64	0.28	0.00	0.51	0.00	0.00	2.43
2004	1.67	0.32	0.00	0.50	0.00	0.00	2.49
2005	1.70	0.34	0.00	0.50	0.00	0.00	2.53
2006	1.73	0.36	0.00	0.49	0.00	0.00	2.57
2007	1.75	0.39	0.00	0.48	0.00	0.00	2.62
2008	1.78	0.43	0.00	0.47	0.00	0.00	2.68
2009	1.81	0.44	0.00	0.48	0.00	0.00	2.73
2010	1.85	0.40	0.00	0.47	0.00	0.00	2.73
2011	1.90	0.41	0.00	0.47	0.00	0.00	2.78
2012	1.94	0.42	0.00	0.47	0.00	0.00	2.83
2013	1.98	0.43	0.00	0.46	0.00	0.00	2.87
2014	2.02	0.44	0.00	0.46	0.00	0.00	2.92
2015	2.06	0.44	0.00	0.46	0.00	0.00	2.96
2016	2.10	0.45	0.00	0.45	0.00	0.00	3.00
2017	2.14	0.46	0.00	0.45	0.00	0.00	3.04

Adopted March 18, 1998

Table H-9

SoCal Gas Service Area
Base Case
Cogen Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.67
1991							3.22
1992							3.13
1993							3.14
1994							2.65
1995							2.26
1996							2.94
1997	1.99	0.39	0.14	0.17	0.12	0.07	2.87
1998	1.81	0.23	0.13	0.18	0.12	0.06	2.52
1999	1.48	0.21	0.09	0.18	0.12	0.05	2.13
2000	1.52	0.23	0.03	0.18	0.00	0.03	1.99
2001	1.56	0.25	0.02	0.18	0.00	0.03	2.04
2002	1.60	0.26	0.02	0.18	0.00	0.03	2.08
2003	1.64	0.28	0.02	0.17	0.00	0.03	2.14
2004	1.67	0.32	0.01	0.17	0.00	0.03	2.19
2005	1.70	0.34	0.01	0.17	0.00	0.03	2.24
2006	1.73	0.36	0.01	0.17	0.00	0.03	2.28
2007	1.75	0.39	0.00	0.16	0.00	0.03	2.33
2008	1.78	0.43	0.00	0.16	0.00	0.03	2.40
2009	1.81	0.44	0.00	0.16	0.00	0.03	2.44
2010	1.85	0.40	0.00	0.16	0.00	0.03	2.44
2011	1.90	0.41	0.00	0.16	0.00	0.03	2.49
2012	1.94	0.42	0.00	0.16	0.00	0.03	2.54
2013	1.98	0.43	0.00	0.16	0.00	0.03	2.59
2014	2.02	0.44	0.00	0.16	0.00	0.03	2.64
2015	2.06	0.44	0.00	0.16	0.00	0.03	2.68
2016	2.10	0.45	0.00	0.15	0.00	0.03	2.73
2017	2.14	0.46	0.00	0.15	0.00	0.03	2.77

Adopted March 18, 1998

Table H-9 (continued)

SoCal Gas Service Area
Base Case
Electricity Generation Noncore Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.67
1991							3.22
1992							3.13
1993							3.14
1994							2.65
1995							2.26
1996							2.94
1997	1.99	0.39	0.14	0.17	0.12	0.07	2.87
1998	1.81	0.23	0.13	0.18	0.12	0.06	2.52
1999	1.48	0.21	0.09	0.18	0.12	0.05	2.13
2000	1.52	0.23	0.03	0.18	0.00	0.03	1.99
2001	1.56	0.25	0.02	0.18	0.00	0.03	2.04
2002	1.60	0.26	0.02	0.18	0.00	0.03	2.08
2003	1.64	0.28	0.02	0.17	0.00	0.03	2.14
2004	1.67	0.32	0.01	0.17	0.00	0.03	2.19
2005	1.70	0.34	0.01	0.17	0.00	0.03	2.24
2006	1.73	0.36	0.01	0.17	0.00	0.03	2.28
2007	1.75	0.39	0.00	0.16	0.00	0.03	2.33
2008	1.78	0.43	0.00	0.16	0.00	0.03	2.40
2009	1.81	0.44	0.00	0.16	0.00	0.03	2.44
2010	1.85	0.40	0.00	0.16	0.00	0.03	2.44
2011	1.90	0.41	0.00	0.16	0.00	0.03	2.49
2012	1.94	0.42	0.00	0.16	0.00	0.03	2.54
2013	1.98	0.43	0.00	0.16	0.00	0.03	2.59
2014	2.02	0.44	0.00	0.16	0.00	0.03	2.64
2015	2.06	0.44	0.00	0.16	0.00	0.03	2.68
2016	2.10	0.45	0.00	0.15	0.00	0.03	2.73
2017	2.14	0.46	0.00	0.15	0.00	0.03	2.77

Adopted March 18, 1998

Table H-10

SoCal Gas Service Area
Base Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

Year	Commodity	Transportation Interstate	Transportation Intrastate	Total Price
1990				3.51
1991				3.11
1992				3.00
1993				3.02
1994				2.55
1995				2.20
1996				2.85
1997	1.94	0.38	0.48	2.80
1998	1.76	0.22	0.47	2.46
1999	1.45	0.21	0.43	2.08
2000	1.48	0.23	0.23	1.94
2001	1.52	0.24	0.22	1.99
2002	1.56	0.25	0.22	2.03
2003	1.60	0.28	0.21	2.09
2004	1.63	0.31	0.20	2.14
2005	1.66	0.33	0.20	2.19
2006	1.68	0.35	0.19	2.22
2007	1.71	0.38	0.19	2.27
2008	1.74	0.42	0.18	2.34
2009	1.77	0.43	0.19	2.38
2010	1.81	0.39	0.18	2.38
2011	1.85	0.40	0.18	2.43
2012	1.89	0.41	0.18	2.48
2013	1.93	0.42	0.18	2.53
2014	1.97	0.43	0.18	2.58
2015	2.01	0.43	0.18	2.62
2016	2.05	0.44	0.18	2.66
2017	2.09	0.44	0.18	2.71

Adopted March 18, 1998

Table H-10 (continued)

SoCal Gas Service Area
Base Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

Year	Commodity	Transportation		Total Price	Cogen Gas Price
		Interstate	Intrastate		
1990				3.05	3.05
1991				2.81	2.81
1992				2.79	2.79
1993				2.88	2.88
1994				2.49	2.49
1995				2.20	2.20
1996				2.91	2.91
1997	2.02	0.39	0.50	2.91	2.91
1998	1.87	0.24	0.50	2.61	2.61
1999	1.58	0.23	0.46	2.27	2.27
2000	1.66	0.25	0.25	2.17	2.17
2001	1.75	0.28	0.26	2.29	2.29
2002	1.85	0.30	0.26	2.40	2.40
2003	1.95	0.34	0.26	2.55	2.55
2004	2.05	0.39	0.26	2.69	2.69
2005	2.16	0.43	0.26	2.85	2.85
2006	2.27	0.47	0.26	3.00	3.00
2007	2.38	0.53	0.26	3.17	3.17
2008	2.51	0.61	0.26	3.38	3.38
2009	2.64	0.65	0.28	3.57	3.57
2010	2.80	0.61	0.29	3.69	3.69
2011	2.97	0.65	0.29	3.90	3.90
2012	3.14	0.68	0.30	4.12	4.12
2013	3.32	0.72	0.31	4.35	4.35
2014	3.51	0.76	0.32	4.59	4.59
2015	3.71	0.80	0.33	4.83	4.83
2016	3.92	0.84	0.34	5.10	5.10
2017	4.14	0.88	0.35	5.37	5.37

Adopted March 18, 1998

Table H-11

SDG&E Service Area

Base Case

End-Use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.43	6.61	6.40	4.41	4.41	0.00	3.71	3.71	5.06
1991	6.05	6.13	6.13	3.88	3.88	0.00	3.25	3.25	4.61
1992	6.45	6.67	6.67	4.02	4.02	0.00	3.20	3.20	4.71
1993	6.85	6.87	6.44	3.81	3.96	0.00	3.33	3.33	4.97
1994	6.89	6.71	5.53	3.60	3.90	0.00	3.04	3.04	4.88
1995	6.44	6.32	5.31	2.71	2.74	0.00	2.18	2.18	4.01
1996	6.66	6.25	5.01	3.01	3.03	0.00	2.53	2.53	4.41
1997	6.88	6.18	4.72	3.32	3.32	0.00	3.07	3.07	4.56
1998	6.51	5.82	4.38	2.98	2.98	0.00	2.81	2.81	4.20
1999	6.23	5.54	4.08	2.62	2.62	0.00	2.41	2.41	3.94
2000	6.24	5.55	4.11	2.60	2.60	0.00	2.39	2.39	3.89
2001	6.29	5.60	4.16	2.64	2.64	0.00	2.43	2.43	3.94
2002	6.10	5.44	4.08	2.68	2.68	0.00	2.47	2.47	3.62
2003	6.17	5.51	4.14	2.73	2.73	0.00	2.50	2.50	3.73
2004	6.14	5.49	4.15	2.77	2.77	0.00	2.55	2.55	3.72
2005	6.15	5.51	4.18	2.80	2.80	0.00	2.59	2.58	3.78
2006	6.08	5.45	4.16	2.83	2.83	0.00	2.62	2.61	3.72
2007	6.04	5.42	4.16	2.86	2.86	0.00	2.65	2.65	3.70
2008	6.02	5.41	4.18	2.91	2.91	0.00	2.71	2.71	3.71
2009	6.03	5.42	4.20	2.94	2.94	0.00	2.74	2.74	3.78
2010	5.98	5.38	4.18	2.94	2.94	0.00	2.74	2.74	3.76
2011	5.95	5.36	4.19	2.98	2.98	0.00	2.79	2.79	3.76
2012	5.94	5.36	4.21	3.02	3.02	0.00	2.83	2.83	3.78
2013	5.93	5.36	4.23	3.06	3.06	0.00	2.88	2.87	3.79
2014	5.93	5.36	4.25	3.10	3.10	0.00	2.91	2.91	3.82
2015	5.93	5.37	4.27	3.13	3.13	0.00	2.95	2.95	3.86
2016	5.93	5.38	4.29	3.17	3.17	0.00	3.00	2.99	3.88
2017	5.92	5.37	4.31	3.21	3.21	0.00	3.03	3.03	3.90

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:
- 1990-1995 total prices are historical , obtained from QFER 7; 1996 is interpolated.
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- SDG&E Margin: Distribution and administration costs associated with running the SDG&E pipeline system and transmission charges to SoCal Gas.
- PITCO/POPCO: Global settlement associated with PITCO and POPCO long term supply contracts.
- Regulatory: Includes balancing accounts, social, environmental and other regulatory accounts.

Adopted March 18, 1998

Table H-12

SDG&E Service Area
Base Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.43
1991							6.05
1992							6.45
1993							6.85
1994							6.89
1995							6.44
1996							6.66
1997	2.09	0.24	0.03	4.24	0.00	0.27	6.88
1998	1.74	0.28	0.03	4.19	0.00	0.27	6.51
1999	1.42	0.29	0.03	4.21	0.00	0.27	6.23
2000	1.46	0.30	0.03	4.17	0.00	0.27	6.24
2001	1.50	0.31	0.03	4.18	0.00	0.27	6.29
2002	1.55	0.31	0.02	3.95	0.00	0.27	6.10
2003	1.59	0.33	0.02	3.96	0.00	0.27	6.17
2004	1.62	0.35	0.01	3.88	0.00	0.27	6.14
2005	1.64	0.37	0.01	3.86	0.00	0.27	6.15
2006	1.67	0.38	0.01	3.75	0.00	0.27	6.08
2007	1.70	0.41	0.00	3.66	0.00	0.27	6.04
2008	1.73	0.45	0.00	3.57	0.00	0.27	6.02
2009	1.76	0.46	0.00	3.54	0.00	0.27	6.03
2010	1.80	0.42	0.00	3.48	0.00	0.27	5.98
2011	1.85	0.43	0.00	3.40	0.00	0.27	5.95
2012	1.89	0.44	0.00	3.34	0.00	0.27	5.94
2013	1.93	0.45	0.00	3.28	0.00	0.27	5.93
2014	1.97	0.46	0.00	3.23	0.00	0.27	5.93
2015	2.01	0.46	0.00	3.19	0.00	0.27	5.93
2016	2.05	0.47	0.00	3.14	0.00	0.27	5.93
2017	2.09	0.47	0.00	3.08	0.00	0.27	5.92

Adopted March 18, 1998

Table H-12 (continued)

SDG&E Service Area
Base Case
Commercial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.61
1991							6.13
1992							6.67
1993							6.87
1994							6.71
1995							6.32
1996							6.25
1997	2.09	0.24	0.03	3.70	0.00	0.12	6.18
1998	1.74	0.28	0.03	3.65	0.00	0.12	5.82
1999	1.42	0.29	0.03	3.67	0.00	0.12	5.54
2000	1.46	0.30	0.03	3.64	0.00	0.12	5.55
2001	1.50	0.31	0.03	3.64	0.00	0.12	5.60
2002	1.55	0.31	0.02	3.44	0.00	0.12	5.44
2003	1.59	0.33	0.02	3.45	0.00	0.12	5.51
2004	1.62	0.35	0.01	3.38	0.00	0.12	5.49
2005	1.64	0.37	0.01	3.36	0.00	0.12	5.51
2006	1.67	0.38	0.01	3.27	0.00	0.12	5.45
2007	1.70	0.41	0.00	3.19	0.00	0.12	5.42
2008	1.73	0.45	0.00	3.11	0.00	0.12	5.41
2009	1.76	0.46	0.00	3.08	0.00	0.12	5.42
2010	1.80	0.42	0.00	3.03	0.00	0.12	5.38
2011	1.85	0.43	0.00	2.96	0.00	0.12	5.36
2012	1.89	0.44	0.00	2.91	0.00	0.12	5.36
2013	1.93	0.45	0.00	2.86	0.00	0.12	5.36
2014	1.97	0.46	0.00	2.81	0.00	0.12	5.36
2015	2.01	0.46	0.00	2.78	0.00	0.12	5.37
2016	2.05	0.47	0.00	2.73	0.00	0.12	5.38
2017	2.09	0.47	0.00	2.69	0.00	0.12	5.37

Adopted March 18, 1998

Table H-12 (continued)

SDG&E Service Area
Base Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.40
1991							6.13
1992							6.67
1993							6.44
1994							5.53
1995							5.31
1996							5.01
1997	2.09	0.24	0.03	2.23	0.00	0.12	4.72
1998	1.74	0.28	0.03	2.20	0.00	0.12	4.38
1999	1.42	0.29	0.03	2.21	0.00	0.12	4.08
2000	1.46	0.30	0.03	2.20	0.00	0.12	4.11
2001	1.50	0.31	0.03	2.20	0.00	0.12	4.16
2002	1.55	0.31	0.02	2.08	0.00	0.12	4.08
2003	1.59	0.33	0.02	2.08	0.00	0.12	4.14
2004	1.62	0.35	0.01	2.04	0.00	0.12	4.15
2005	1.64	0.37	0.01	2.03	0.00	0.12	4.18
2006	1.67	0.38	0.01	1.97	0.00	0.12	4.16
2007	1.70	0.41	0.00	1.92	0.00	0.12	4.16
2008	1.73	0.45	0.00	1.88	0.00	0.12	4.18
2009	1.76	0.46	0.00	1.86	0.00	0.12	4.20
2010	1.80	0.42	0.00	1.83	0.00	0.12	4.18
2011	1.85	0.43	0.00	1.79	0.00	0.12	4.19
2012	1.89	0.44	0.00	1.76	0.00	0.12	4.21
2013	1.93	0.45	0.00	1.72	0.00	0.12	4.23
2014	1.97	0.46	0.00	1.70	0.00	0.12	4.25
2015	2.01	0.46	0.00	1.68	0.00	0.12	4.27
2016	2.05	0.47	0.00	1.65	0.00	0.12	4.29
2017	2.09	0.47	0.00	1.62	0.00	0.12	4.31

Adopted March 18, 1998

Table H-13

SDG&E Service Area
Base Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.41
1991							3.88
1992							4.02
1993							3.81
1994							3.60
1995							2.71
1996							3.01
1997	2.09	0.24	0.15	0.81	0.00	0.03	3.32
1998	1.74	0.28	0.14	0.79	0.00	0.03	2.98
1999	1.42	0.29	0.10	0.77	0.00	0.03	2.62
2000	1.46	0.30	0.03	0.77	0.00	0.03	2.60
2001	1.50	0.31	0.03	0.77	0.00	0.03	2.64
2002	1.55	0.31	0.02	0.77	0.00	0.03	2.68
2003	1.59	0.33	0.02	0.76	0.00	0.03	2.73
2004	1.62	0.35	0.01	0.75	0.00	0.03	2.77
2005	1.64	0.37	0.01	0.74	0.00	0.03	2.80
2006	1.67	0.38	0.01	0.73	0.00	0.03	2.83
2007	1.70	0.41	0.00	0.72	0.00	0.03	2.86
2008	1.73	0.45	0.00	0.70	0.00	0.03	2.91
2009	1.76	0.46	0.00	0.69	0.00	0.03	2.94
2010	1.80	0.42	0.00	0.68	0.00	0.03	2.94
2011	1.85	0.43	0.00	0.67	0.00	0.03	2.98
2012	1.89	0.44	0.00	0.66	0.00	0.03	3.02
2013	1.93	0.45	0.00	0.65	0.00	0.03	3.06
2014	1.97	0.46	0.00	0.64	0.00	0.03	3.10
2015	2.01	0.46	0.00	0.63	0.00	0.03	3.13
2016	2.05	0.47	0.00	0.62	0.00	0.03	3.17
2017	2.09	0.47	0.00	0.61	0.00	0.03	3.21

Adopted March 18, 1998

Table H-13 (continued)

SDG&E Service Area
Base Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.41
1991							3.88
1992							4.02
1993							3.96
1994							3.90
1995							2.74
1996							3.03
1997	2.09	0.24	0.15	0.81	0.00	0.03	3.32
1998	1.74	0.28	0.14	0.79	0.00	0.03	2.98
1999	1.42	0.29	0.10	0.77	0.00	0.03	2.62
2000	1.46	0.30	0.03	0.77	0.00	0.03	2.60
2001	1.50	0.31	0.03	0.77	0.00	0.03	2.64
2002	1.55	0.31	0.02	0.77	0.00	0.03	2.68
2003	1.59	0.33	0.02	0.76	0.00	0.03	2.73
2004	1.62	0.35	0.01	0.75	0.00	0.03	2.77
2005	1.64	0.37	0.01	0.74	0.00	0.03	2.80
2006	1.67	0.38	0.01	0.73	0.00	0.03	2.83
2007	1.70	0.41	0.00	0.72	0.00	0.03	2.86
2008	1.73	0.45	0.00	0.70	0.00	0.03	2.91
2009	1.76	0.46	0.00	0.69	0.00	0.03	2.94
2010	1.80	0.42	0.00	0.68	0.00	0.03	2.94
2011	1.85	0.43	0.00	0.67	0.00	0.03	2.98
2012	1.89	0.44	0.00	0.66	0.00	0.03	3.02
2013	1.93	0.45	0.00	0.65	0.00	0.03	3.06
2014	1.97	0.46	0.00	0.64	0.00	0.03	3.10
2015	2.01	0.46	0.00	0.63	0.00	0.03	3.13
2016	2.05	0.47	0.00	0.62	0.00	0.03	3.17
2017	2.09	0.47	0.00	0.61	0.00	0.03	3.21

Adopted March 18, 1998

Table H-14

SDG&E Service Area
Base Case
Cogen Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	2.09	0.24	0.15	0.49	0.00	0.10	3.07
1998	1.74	0.28	0.14	0.55	0.00	0.10	2.81
1999	1.42	0.29	0.10	0.49	0.00	0.10	2.41
2000	1.46	0.30	0.03	0.49	0.00	0.10	2.39
2001	1.50	0.31	0.03	0.49	0.00	0.10	2.43
2002	1.55	0.31	0.02	0.49	0.00	0.10	2.47
2003	1.59	0.33	0.02	0.47	0.00	0.10	2.50
2004	1.62	0.35	0.01	0.47	0.00	0.10	2.55
2005	1.64	0.37	0.01	0.46	0.00	0.10	2.59
2006	1.67	0.38	0.01	0.45	0.00	0.10	2.62
2007	1.70	0.41	0.00	0.44	0.00	0.10	2.65
2008	1.73	0.45	0.00	0.43	0.00	0.10	2.71
2009	1.76	0.46	0.00	0.42	0.00	0.10	2.74
2010	1.80	0.42	0.00	0.41	0.00	0.10	2.74
2011	1.85	0.43	0.00	0.41	0.00	0.10	2.79
2012	1.89	0.44	0.00	0.40	0.00	0.10	2.83
2013	1.93	0.45	0.00	0.39	0.00	0.10	2.88
2014	1.97	0.46	0.00	0.39	0.00	0.10	2.91
2015	2.01		0.00	0.38	0.00	0.10	2.95
2016	2.05	0.47	0.00	0.37	0.00	0.10	3.00
2017	2.09	0.47	0.00	0.37	0.00	0.10	3.03

Adopted March 18, 1998

Table H-14 (continued)

SDG&E Service Area
Base Case
Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	2.09	0.24	0.15	0.49	0.00	0.10	3.07
1998	1.74	0.28	0.14	0.55	0.00	0.10	2.81
1999	1.42	0.29	0.10	0.49	0.00	0.10	2.41
2000	1.46	0.30	0.03	0.49	0.00	0.10	2.39
2001	1.50	0.31	0.03	0.49	0.00	0.10	2.43
2002	1.55	0.31	0.02	0.49	0.00	0.10	2.47
2003	1.59	0.33	0.02	0.47	0.00	0.10	2.50
2004	1.62	0.35	0.01	0.47	0.00	0.10	2.55
2005	1.64	0.37	0.01	0.46	0.00	0.10	2.58
2006	1.67	0.38	0.01	0.45	0.00	0.10	2.61
2007	1.70	0.41	0.00	0.44	0.00	0.10	2.65
2008	1.73	0.45	0.00	0.43	0.00	0.10	2.71
2009	1.76	0.46	0.00	0.42	0.00	0.10	2.74
2010	1.80	0.42	0.00	0.41	0.00	0.10	2.74
2011	1.85	0.43	0.00	0.41	0.00	0.10	2.79
2012	1.89	0.44	0.00	0.40	0.00	0.10	2.83
2013	1.93	0.45	0.00	0.39	0.00	0.10	2.87
2014	1.97	0.46	0.00	0.39	0.00	0.10	2.91
2015	2.01	0.46	0.00	0.38	0.00	0.10	2.95
2016	2.05	0.47	0.00	0.37	0.00	0.10	2.99
2017	2.09	0.47	0.00	0.37	0.00	0.10	3.03

Adopted March 18, 1998

Table H-15

SDG&E Service Area
Base Case
Electricity Generation Natural Gas Price Forecast

1995 $ per mmBtu

Year	**Commodity**	**Transportation** **Interstate**	**Intrastate**	**Total Price**
1990			2.11	3.60
1991			2.03	3.16
1992			2.10	3.10
1993			2.12	3.24
1994			2.09	2.98
1995			2.09	2.14
1996			1.39	2.50
1997	2.04	0.24	0.72	3.00
1998	1.70	0.28	0.77	2.74
1999	1.39	0.29	0.67	2.35
2000	1.43	0.30	0.61	2.33
2001	1.46	0.31	0.60	2.37
2002	1.51	0.30	0.59	2.41
2003	1.55	0.32	0.57	2.44
2004	1.58	0.34	0.56	2.49
2005	1.60	0.36	0.55	2.52
2006	1.63	0.38	0.54	2.55
2007	1.66	0.40	0.53	2.59
2008	1.69	0.43	0.51	2.64
2009	1.72	0.45	0.51	2.67
2010	1.76	0.41	0.50	2.67
2011	1.80	0.42	0.49	2.72
2012	1.84	0.43	0.49	2.76
2013	1.88	0.44	0.48	2.80
2014	1.92	0.45	0.47	2.84
2015	1.96	0.45	0.47	2.88
2016	2.00	0.46	0.46	2.92
2017	2.04	0.46	0.46	2.96

Adopted March 18, 1998

Table H-15 (continued)

SDG&E Service Area
Base Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Electricity Generation				Cogen
		Transportation		Total	Gas
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990			1.84	3.13	3.13
1991			1.83	2.86	2.86
1992			1.95	2.88	2.88
1993			2.02	3.09	3.09
1994			2.04	2.90	2.90
1995			2.09	2.14	2.14
1996			1.42	2.55	2.55
1997	2.11	0.25	0.75	3.12	3.12
1998	1.80	0.29	0.82	2.91	2.91
1999	1.51	0.31	0.73	2.56	2.56
2000	1.60	0.33	0.68	2.61	2.61
2001	1.68	0.35	0.69	2.73	2.73
2002	1.79	0.36	0.70	2.85	2.85
2003	1.89	0.39	0.70	2.98	2.98
2004	1.99	0.43	0.71	3.13	3.13
2005	2.09	0.47	0.72	3.28	3.28
2006	2.20	0.51	0.73	3.43	3.43
2007	2.31	0.56	0.73	3.61	3.61
2008	2.44	0.63	0.74	3.81	3.81
2009	2.57	0.67	0.76	3.99	3.99
2010	2.72	0.64	0.78	4.14	4.14
2011	2.89	0.68	0.79	4.36	4.36
2012	3.06	0.71	0.81	4.58	4.58
2013	3.24	0.76	0.82	4.82	4.82
2014	3.42	0.79	0.84	5.06	5.06
2015	3.62	0.83	0.86	5.31	5.31
2016	3.82	0.88	0.89	5.59	5.59
2017	4.04	0.92	0.91	5.86	5.86

Adopted March 18, 1998

APPENDIX I
LOW NATURAL GAS PRICE FORECAST

The Low Price Forecast was prepared by the California Energy Commission for the ***Fuels Report*** to analyze the impact of natural gas price uncertainty. It is a lower extreme that is possible under the assumptions made, but not sustainable. As such, the Low Price Forecast represents a lower bound to the Basecase forecast. In these tables, the natural gas price forecast for electricity generation has been converted to current $/mmbtu.

Table I-1

PG&E Service Area
Low Price Case
End-use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.42	6.33	5.59	3.63	3.94	2.93	3.65	3.65	4.40
1991	6.44	6.44	5.64	2.99	3.14	3.47	3.15	3.15	4.25
1992	6.20	6.77	5.04	2.89	2.31	2.72	2.87	2.87	4.51
1993	5.92	6.28	4.97	3.10	2.30	2.43	3.10	3.10	3.69
1994	6.11	6.32	4.65	3.02	2.06	2.05	2.32	2.32	3.62
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1996	6.74	6.77	4.68	3.08	2.42	2.14	2.36	2.36	4.09
1997	7.13	7.12	4.69	3.63	2.98	2.76	2.65	2.65	4.31
1998	6.78	7.32	4.22	3.39	2.39	2.37	2.24	2.24	3.94
1999	6.36	6.35	3.48	2.98	2.00	1.99	1.78	1.78	3.46
2000	6.12	6.10	3.42	2.83	1.87	1.86	1.66	1.66	3.24
2001	5.94	5.93	3.42	2.81	1.86	1.86	1.69	1.69	3.20
2002	5.76	5.75	3.42	2.81	1.87	1.88	1.70	1.70	3.13
2003	5.73	5.73	3.43	2.82	1.89	1.89	1.72	1.72	3.12
2004	5.73	5.72	3.45	2.82	1.90	1.90	1.74	1.74	3.14
2005	5.70	5.69	3.45	2.82	1.92	1.92	1.77	1.77	3.13
2006	5.66	5.65	3.45	2.83	1.93	1.93	1.79	1.79	3.09
2007	5.66	5.65	3.46	2.83	1.95	1.94	1.81	1.81	3.11
2008	5.61	5.60	3.46	2.83	1.96	1.95	1.83	1.83	3.09
2009	5.62	5.61	3.48	2.85	1.98	1.97	1.85	1.85	3.09
2010	5.62	5.61	3.51	2.85	1.99	1.98	1.87	1.87	3.10
2011	5.61	5.61	3.53	2.85	2.00	1.99	1.89	1.89	3.12
2012	5.59	5.59	3.54	2.86	2.02	2.00	1.92	1.92	3.10
2013	5.59	5.59	3.55	2.86	2.03	2.01	1.94	1.94	3.12
2014	5.58	5.58	3.57	2.87	2.05	2.03	1.96	1.96	3.13
2015	5.58	5.58	3.59	2.88	2.07	2.05	1.99	1.99	3.14
2016	5.59	5.59	3.62	2.90	2.09	2.07	2.01	2.01	3.16
2017	5.60	5.60	3.64	2.91	2.11	2.08	2.04	2.04	3.17

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical, obtained from QFER 7.
- 1997 margin based on PG&E Advice No. 1978-G, November 15, 1998.
- Remaining years margin based on PG&E Revised BCAP Application No. 97-03-002 and associated work papers (Aug. 18 and 27, 1997).
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- PG&E Margin: Includes base margin, access charges, portion of the backbone costs, local transmission, and core storage.
- PG&E Backbone: Weighted average transmission charge to transport natural gas on Line 300, phased in Line 400/401, and incremental Line 401.
- Regulatory: Instate charge to recover customer class charges, including balancing accounts, social, environmental, and other regulatory accounts.

Adopted March, 1998

Table I-2

PG&E Service Area
Low Price Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							6.42
1991							6.44
1992							6.20
1993							5.92
1994							6.11
1995							6.35
1996							6.74
1997	1.72	0.46	0.04	4.43	0.00	0.49	7.13
1998	1.47	0.46	0.04	3.95	0.12	0.74	6.78
1999	1.24	0.47	0.04	3.90	0.12	0.58	6.36
2000	1.27	0.47	0.00	3.83	0.12	0.43	6.12
2001	1.31	0.47	0.00	3.78	0.12	0.27	5.94
2002	1.34	0.47	0.00	3.72	0.12	0.12	5.76
2003	1.37	0.47	0.00	3.67	0.12	0.12	5.73
2004	1.39	0.46	0.00	3.63	0.12	0.12	5.73
2005	1.42	0.46	0.00	3.58	0.12	0.12	5.70
2006	1.44	0.46	0.00	3.52	0.12	0.12	5.66
2007	1.47	0.46	0.00	3.49	0.12	0.12	5.66
2008	1.49	0.46	0.00	3.41	0.12	0.12	5.61
2009	1.52	0.46	0.00	3.40	0.12	0.12	5.62
2010	1.56	0.46	0.00	3.36	0.12	0.12	5.62
2011	1.60	0.46	0.00	3.32	0.12	0.12	5.61
2012	1.63	0.46	0.00	3.27	0.12	0.12	5.59
2013	1.65	0.46	0.00	3.24	0.12	0.12	5.59
2014	1.68	0.47	0.00	3.20	0.12	0.12	5.58
2015	1.72	0.47	0.00	3.16	0.12	0.12	5.58
2016	1.76	0.47	0.00	3.13	0.12	0.12	5.59
2017	1.79	0.47	0.00	3.10	0.12	0.12	5.60

Adopted March 18, 1998

Table I-2 (continued)

PG&E Service Area
Low Price Case
Commercial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							6.33
1991							6.44
1992							6.77
1993							6.28
1994							6.32
1995							6.41
1996							6.77
1997	1.72	0.46	0.04	4.43	0.00	0.48	7.12
1998	1.47	0.46	0.04	4.43	0.12	0.80	7.32
1999	1.24	0.47	0.04	3.83	0.12	0.64	6.35
2000	1.27	0.47	0.00	3.76	0.12	0.49	6.10
2001	1.31	0.47	0.00	3.71	0.12	0.33	5.93
2002	1.34	0.47	0.00	3.65	0.12	0.18	5.75
2003	1.37	0.47	0.00	3.60	0.12	0.18	5.73
2004	1.39	0.46	0.00	3.57	0.12	0.18	5.72
2005	1.42	0.46	0.00	3.52	0.12	0.18	5.69
2006	1.44	0.46	0.00	3.46	0.12	0.18	5.65
2007	1.47	0.46	0.00	3.43	0.12	0.18	5.65
2008	1.49	0.46	0.00	3.35	0.12	0.18	5.60
2009	1.52	0.46	0.00	3.34	0.12	0.18	5.61
2010	1.56	0.46	0.00	3.30	0.12	0.18	5.61
2011	1.60	0.46	0.00	3.26	0.12	0.18	5.61
2012	1.63	0.46	0.00	3.21	0.12	0.18	5.59
2013	1.65	0.46	0.00	3.18	0.12	0.18	5.59
2014	1.68	0.47	0.00	3.14	0.12	0.18	5.58
2015	1.72	0.47	0.00	3.10	0.12	0.18	5.58
2016	1.76	0.47	0.00	3.08	0.12	0.18	5.59
2017	1.79	0.47	0.00	3.05	0.12	0.18	5.60

Adopted March 18, 1998

Table I-2 (continued)

PG&E Service Area
Low Price Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							5.59
1991							5.64
1992							5.04
1993							4.97
1994							4.65
1995							4.67
1996							4.68
1997	1.72	0.46	0.04	2.40	0.00	0.08	4.69
1998	1.47	0.46	0.04	2.00	0.12	0.12	4.22
1999	1.24	0.47	0.04	1.49	0.12	0.11	3.48
2000	1.27	0.47	0.00	1.46	0.12	0.10	3.42
2001	1.31	0.47	0.00	1.44	0.12	0.09	3.42
2002	1.34	0.47	0.00	1.42	0.12	0.08	3.42
2003	1.37	0.47	0.00	1.40	0.12	0.08	3.43
2004	1.39	0.46	0.00	1.39	0.12	0.08	3.45
2005	1.42	0.46	0.00	1.37	0.12	0.08	3.45
2006	1.44	0.46	0.00	1.34	0.12	0.08	3.45
2007	1.47	0.46	0.00	1.33	0.12	0.08	3.46
2008	1.49	0.46	0.00	1.30	0.12	0.08	3.46
2009	1.52	0.46	0.00	1.30	0.12	0.08	3.48
2010	1.56	0.46	0.00	1.28	0.12	0.08	3.51
2011	1.60	0.46	0.00	1.27	0.12	0.08	3.53
2012	1.63	0.46	0.00	1.25	0.12	0.08	3.54
2013	1.65	0.46	0.00	1.24	0.12	0.08	3.55
2014	1.68	0.47	0.00	1.22	0.12	0.08	3.57
2015	1.72	0.47	0.00	1.20	0.12	0.08	3.59
2016	1.76	0.47	0.00	1.20	0.12	0.08	3.62
2017	1.79	0.47	0.00	1.18	0.12	0.08	3.64

Adopted March 18, 1998

Table I-3

PG&E Service Area
Low Price Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.63
1991							2.99
1992							2.89
1993							3.10
1994							3.02
1995							2.52
1996							3.08
1997	1.71	0.46	0.10	1.28	0.00	0.08	3.63
1998	1.33	0.46	0.14	1.21	0.12	0.14	3.39
1999	0.96	0.46	0.14	1.18	0.12	0.13	2.98
2000	0.98	0.45	0.00	1.17	0.12	0.12	2.83
2001	0.99	0.45	0.00	1.15	0.12	0.11	2.81
2002	1.01	0.45	0.00	1.13	0.12	0.10	2.81
2003	1.03	0.45	0.00	1.12	0.12	0.10	2.82
2004	1.05	0.45	0.00	1.10	0.12	0.10	2.82
2005	1.06	0.45	0.00	1.09	0.12	0.10	2.82
2006	1.08	0.45	0.00	1.08	0.12	0.10	2.83
2007	1.10	0.45	0.00	1.07	0.12	0.10	2.83
2008	1.11	0.45	0.00	1.05	0.12	0.10	2.83
2009	1.13	0.46	0.00	1.05	0.12	0.10	2.85
2010	1.15	0.45	0.00	1.03	0.12	0.10	2.85
2011	1.16	0.45	0.00	1.02	0.12	0.10	2.85
2012	1.18	0.45	0.00	1.01	0.12	0.10	2.86
2013	1.20	0.45	0.00	0.99	0.12	0.10	2.86
2014	1.21	0.45	0.00	0.98	0.12	0.10	2.87
2015	1.23	0.45	0.00	0.97	0.12	0.10	2.88
2016	1.26	0.46	0.00	0.97	0.12	0.10	2.90
2017	1.27	0.46	0.00	0.96	0.12	0.10	2.91

Adopted March 18, 1998

Table I-3 (continued)

PG&E Service Area
Low Price Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.94
1991							3.14
1992							2.31
1993							2.30
1994							2.06
1995							1.85
1996							2.42
1997	1.71	0.46	0.10	0.63	0.00	0.08	2.98
1998	1.33	0.46	0.14	0.22	0.12	0.12	2.39
1999	0.96	0.46	0.14	0.22	0.12	0.11	2.00
2000	0.98	0.45	0.00	0.21	0.12	0.10	1.87
2001	0.99	0.45	0.00	0.21	0.12	0.09	1.86
2002	1.01	0.45	0.00	0.21	0.12	0.08	1.87
2003	1.03	0.45	0.00	0.20	0.12	0.08	1.89
2004	1.05	0.45	0.00	0.20	0.12	0.08	1.90
2005	1.06	0.45	0.00	0.20	0.12	0.08	1.92
2006	1.08	0.45	0.00	0.20	0.12	0.08	1.93
2007	1.10	0.45	0.00	0.19	0.12	0.08	1.95
2008	1.11	0.45	0.00	0.19	0.12	0.08	1.96
2009	1.13	0.46	0.00	0.19	0.12	0.08	1.98
2010	1.15	0.45	0.00	0.19	0.12	0.08	1.99
2011	1.16	0.45	0.00	0.19	0.12	0.08	2.00
2012	1.18	0.45	0.00	0.18	0.12	0.08	2.02
2013	1.20	0.45	0.00	0.18	0.12	0.08	2.03
2014	1.21	0.45	0.00	0.18	0.12	0.08	2.05
2015	1.23	0.45	0.00	0.18	0.12	0.08	2.07
2016	1.26	0.46	0.00	0.18	0.12	0.08	2.09
2017	1.27	0.46	0.00	0.18	0.12	0.08	2.11

Adopted March 18, 1998

Table I-3 (continued)

PG&E Service Area
Low Price Case
TEOR Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							2.93
1991							3.47
1992							2.72
1993							2.43
1994							2.05
1995							1.52
1996							2.14
1997	1.71	0.46	0.10	0.49	0.00	0.00	2.76
1998	1.33	0.46	0.14	0.44	0.00	0.00	2.37
1999	0.96	0.46	0.14	0.43	0.00	0.00	1.99
2000	0.98	0.45	0.00	0.43	0.00	0.00	1.86
2001	0.99	0.45	0.00	0.42	0.00	0.00	1.86
2002	1.01	0.45	0.00	0.41	0.00	0.00	1.88
2003	1.03	0.45	0.00	0.41	0.00	0.00	1.89
2004	1.05	0.45	0.00	0.40	0.00	0.00	1.90
2005	1.06	0.45	0.00	0.40	0.00	0.00	1.92
2006	1.08	0.45	0.00	0.40	0.00	0.00	1.93
2007	1.10	0.45	0.00	0.39	0.00	0.00	1.94
2008	1.11	0.45	0.00	0.38	0.00	0.00	1.95
2009	1.13	0.46	0.00	0.38	0.00	0.00	1.97
2010	1.15	0.45	0.00	0.38	0.00	0.00	1.98
2011	1.16	0.45	0.00	0.37	0.00	0.00	1.99
2012	1.18	0.45	0.00	0.37	0.00	0.00	2.00
2013	1.20	0.45	0.00	0.36	0.00	0.00	2.01
2014	1.21	0.45	0.00	0.36	0.00	0.00	2.03
2015	1.23	0.45	0.00	0.36	0.00	0.00	2.05
2016	1.26	0.46	0.00	0.36	0.00	0.00	2.07
2017	1.27	0.46	0.00	0.35	0.00	0.00	2.08

Adopted March 18, 1998

Table I-4

PG&E Service Area
Low Price Case
Cogen Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	1.83	0.20	0.10	0.49	0.00	0.03	2.65
1998	1.40	0.25	0.14	0.20	0.18	0.07	2.24
1999	0.98	0.23	0.14	0.19	0.18	0.06	1.78
2000	0.99	0.25	0.00	0.19	0.18	0.06	1.66
2001	1.01	0.27	0.00	0.19	0.17	0.05	1.69
2002	1.04	0.27	0.00	0.18	0.17	0.04	1.70
2003	1.06	0.28	0.00	0.18	0.17	0.04	1.72
2004	1.07	0.29	0.00	0.18	0.16	0.04	1.74
2005	1.09	0.30	0.00	0.18	0.16	0.04	1.77
2006	1.11	0.31	0.00	0.18	0.15	0.04	1.79
2007	1.12	0.33	0.00	0.17	0.15	0.04	1.81
2008	1.14	0.34	0.00	0.17	0.14	0.04	1.83
2009	1.16	0.35	0.00	0.17	0.14	0.04	1.85
2010	1.20	0.33	0.00	0.17	0.13	0.04	1.87
2011	1.21	0.34	0.00	0.17	0.13	0.04	1.89
2012	1.23	0.35	0.00	0.16	0.13	0.04	1.92
2013	1.25	0.36	0.00	0.16	0.13	0.04	1.94
2014	1.26	0.37	0.00	0.16	0.13	0.04	1.96
2015	1.28	0.37	0.00	0.16	0.13	0.04	1.99
2016	1.31	0.38	0.00	0.16	0.13	0.04	2.01
2017	1.32	0.39	0.00	0.16	0.13	0.04	2.04

Adopted March 18, 1998

Table I-4 (continued)

PG&E Service Area
Low Price Case
Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	1.83	0.20	0.10	0.49	0.00	0.03	2.65
1998	1.40	0.25	0.14	0.20	0.18	0.07	2.24
1999	0.98	0.23	0.14	0.19	0.18	0.06	1.78
2000	0.99	0.25	0.00	0.19	0.18	0.06	1.66
2001	1.01	0.27	0.00	0.19	0.17	0.05	1.69
2002	1.04	0.27	0.00	0.18	0.17	0.04	1.70
2003	1.06	0.28	0.00	0.18	0.17	0.04	1.72
2004	1.07	0.29	0.00	0.18	0.16	0.04	1.74
2005	1.09	0.30	0.00	0.18	0.16	0.04	1.77
2006	1.11	0.31	0.00	0.18	0.15	0.04	1.79
2007	1.12	0.33	0.00	0.17	0.15	0.04	1.81
2008	1.14	0.34	0.00	0.17	0.14	0.04	1.83
2009	1.16	0.35	0.00	0.17	0.14	0.04	1.85
2010	1.20	0.33	0.00	0.17	0.13	0.04	1.87
2011	1.21	0.34	0.00	0.17	0.13	0.04	1.89
2012	1.23	0.35	0.00	0.16	0.13	0.04	1.92
2013	1.25	0.36	0.00	0.16	0.13	0.04	1.94
2014	1.26	0.37	0.00	0.16	0.13	0.04	1.96
2015	1.28	0.37	0.00	0.16	0.13	0.04	1.99
2016	1.31	0.38	0.00	0.16	0.13	0.04	2.01
2017	1.32	0.39	0.00	0.16	0.13	0.04	2.04

Adopted March 18, 1998

Table I-5

PG&E Service Area
Low Price Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

		Transportation		Total
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**
1990				3.55
1991				3.08
1992				2.80
1993				3.02
1994				2.26
1995				2.21
1996				2.32
1997	1.79	0.19	0.61	2.60
1998	1.38	0.25	0.58	2.20
1999	0.96	0.23	0.56	1.75
2000	0.97	0.24	0.41	1.63
2001	0.99	0.26	0.40	1.65
2002	1.02	0.26	0.39	1.67
2003	1.04	0.27	0.38	1.69
2004	1.05	0.28	0.37	1.71
2005	1.07	0.30	0.37	1.73
2006	1.09	0.31	0.36	1.76
2007	1.10	0.32	0.36	1.78
2008	1.12	0.33	0.35	1.80
2009	1.14	0.34	0.34	1.82
2010	1.17	0.33	0.33	1.83
2011	1.19	0.34	0.33	1.86
2012	1.21	0.34	0.33	1.88
2013	1.22	0.35	0.33	1.90
2014	1.24	0.36	0.33	1.92
2015	1.26	0.36	0.32	1.95
2016	1.28	0.37	0.32	1.97
2017	1.30	0.38	0.32	2.00

Adopted March 18, 1998

Table I-5 (continued)

PG&E Service Area
Low Price Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Utility Electric Generation				Cogen
		Transportation		Total	Gas
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990				3.09	3.09
1991				2.79	2.79
1992				2.61	2.61
1993				2.88	2.88
1994				2.20	2.20
1995				2.21	2.21
1996				2.37	2.37
1997	1.86	0.20	0.63	2.70	2.75
1998	1.46	0.26	0.61	2.34	2.39
1999	1.04	0.25	0.61	1.90	1.94
2000	1.09	0.27	0.46	1.82	1.86
2001	1.14	0.30	0.46	1.90	1.94
2002	1.20	0.31	0.46	1.97	2.01
2003	1.26	0.33	0.46	2.06	2.10
2004	1.33	0.36	0.47	2.15	2.20
2005	1.39	0.39	0.48	2.26	2.30
2006	1.46	0.41	0.49	2.36	2.41
2007	1.54	0.45	0.50	2.48	2.53
2008	1.62	0.48	0.50	2.59	2.65
2009	1.70	0.51	0.51	2.72	2.77
2010	1.82	0.51	0.52	2.84	2.90
2011	1.91	0.54	0.53	2.98	3.04
2012	2.00	0.57	0.55	3.12	3.18
2013	2.10	0.60	0.56	3.27	3.33
2014	2.20	0.64	0.58	3.42	3.49
2015	2.32	0.67	0.60	3.59	3.67
2016	2.45	0.71	0.62	3.78	3.85
2017	2.58	0.76	0.64	3.97	4.05

Adopted March 18, 1998

Table I-6

SoCal Gas Service Area
Low Price Case
End-use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			**Noncore**					**System**
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.40	6.76	5.99	4.28	3.79	3.37	3.67	3.67	4.75
1991	6.99	7.34	7.34	3.91	3.64	2.86	3.22	3.22	4.72
1992	6.82	7.66	6.40	5.00	3.75	2.82	3.13	3.13	4.78
1993	7.24	7.65	6.71	4.98	3.73	3.16	3.14	3.14	5.01
1994	7.03	6.81	6.59	3.32	2.48	2.48	2.65	2.65	4.60
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1996	6.73	5.79	4.98	2.72	2.66	2.42	2.94	2.94	4.49
1997	6.77	5.03	4.10	3.04	3.04	2.82	2.86	2.86	4.34
1998	6.27	4.52	3.59	2.56	2.56	2.35	2.34	2.34	3.85
1999	5.72	3.99	3.06	2.04	2.04	1.87	1.78	1.78	3.31
2000	5.60	3.87	2.96	1.92	1.91	1.93	1.64	1.64	3.15
2001	5.57	3.87	2.96	1.96	1.96	1.97	1.68	1.68	3.15
2002	5.53	3.86	2.96	2.00	1.99	2.01	1.72	1.72	3.13
2003	5.55	3.88	2.99	2.03	2.03	2.05	1.76	1.76	3.17
2004	5.43	3.81	2.96	2.06	2.06	2.09	1.79	1.79	3.12
2005	5.47	3.84	2.98	2.10	2.09	2.12	1.83	1.83	3.17
2006	5.35	3.78	2.95	2.12	2.11	2.14	1.85	1.85	3.12
2007	5.32	3.77	2.95	2.19	2.18	2.22	1.93	1.93	3.16
2008	5.28	3.76	2.96	2.21	2.21	2.24	1.96	1.96	3.15
2009	5.37	3.82	3.00	2.25	2.25	2.28	1.99	1.99	3.18
2010	5.34	3.82	3.01	2.24	2.23	2.27	1.98	1.98	3.17
2011	5.30	3.81	3.02	2.26	2.26	2.29	2.00	2.00	3.15
2012	5.33	3.83	3.05	2.29	2.28	2.32	2.03	2.03	3.18
2013	5.30	3.83	3.06	2.31	2.31	2.34	2.06	2.06	3.17
2014	5.32	3.85	3.08	2.33	2.33	2.36	2.08	2.08	3.19
2015	5.30	3.85	3.09	2.36	2.35	2.39	2.11	2.11	3.20
2016	5.29	3.86	3.11	2.39	2.38	2.41	2.14	2.14	3.21
2017	5.29	3.87	3.13	2.41	2.41	2.44	2.17	2.17	3.22

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7; 1996 is interpolated.
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- SoCal Gas Margin: Distribution and administration costs associated with running the SoCal Gas pipeline system.
- PITCO/POPCO: Global settlement associated with PITCO and POPCO long term supply contracts.
- Regulatory: Includes balancing accounts, social, environmental, and other regulatory accounts.

Adopted March 18, 1998

Table I-7

SoCal Gas Service Area
Low Price Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.40
1991							6.99
1992							6.82
1993							7.24
1994							7.03
1995							6.69
1996							6.73
1997	2.15	0.38	0.03	3.83	0.12	0.26	6.77
1998	1.64	0.38	0.03	3.84	0.12	0.26	6.27
1999	1.13	0.37	0.03	3.81	0.12	0.26	5.72
2000	1.15	0.37	0.03	3.78	0.00	0.26	5.60
2001	1.18	0.36	0.03	3.74	0.00	0.26	5.57
2002	1.21	0.36	0.02	3.68	0.00	0.26	5.53
2003	1.24	0.35	0.02	3.68	0.00	0.26	5.55
2004	1.26	0.35	0.01	3.54	0.00	0.26	5.43
2005	1.28	0.35	0.01	3.57	0.00	0.26	5.47
2006	1.30	0.34	0.01	3.44	0.00	0.26	5.35
2007	1.34	0.33	0.00	3.40	0.00	0.26	5.32
2008	1.36	0.33	0.00	3.33	0.00	0.26	5.28
2009	1.38	0.34	0.00	3.39	0.00	0.26	5.37
2010	1.41	0.33	0.00	3.34	0.00	0.26	5.34
2011	1.44	0.33	0.00	3.28	0.00	0.26	5.30
2012	1.46	0.34	0.00	3.27	0.00	0.26	5.33
2013	1.49	0.34	0.00	3.22	0.00	0.26	5.30
2014	1.51	0.34	0.00	3.21	0.00	0.26	5.32
2015	1.54	0.34	0.00	3.16	0.00	0.26	5.30
2016	1.56	0.34	0.00	3.13	0.00	0.26	5.29
2017	1.59	0.34	0.00	3.10	0.00	0.26	5.29

Adopted March 18, 1998

Table I-7 (continued)

SoCal Gas Service Area
Price Case
Commercial Core End-Use Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.76
1991							7.34
1992							7.66
1993							7.65
1994							6.81
1995							6.55
1996							5.79
1997	2.15	0.38	0.03	2.14	0.12	0.21	5.03
1998	1.64	0.38	0.03	2.15	0.12	0.21	4.52
1999	1.13	0.37	0.03	2.13	0.12	0.21	3.99
2000	1.15	0.37	0.03	2.11	0.00	0.21	3.87
2001	1.18	0.36	0.03	2.09	0.00	0.21	3.87
2002	1.21	0.36	0.02	2.06	0.00	0.21	3.86
2003	1.24	0.35	0.02	2.05	0.00	0.21	3.88
2004	1.26	0.35	0.01	1.98	0.00	0.21	3.81
2005	1.28	0.35	0.01	1.99	0.00	0.21	3.84
2006	1.30	0.34	0.01	1.92	0.00	0.21	3.78
2007	1.34	0.33	0.00	1.90	0.00	0.21	3.77
2008	1.36	0.33	0.00	1.86	0.00	0.21	3.76
2009	1.38	0.34	0.00	1.90	0.00	0.21	3.82
2010	1.41	0.33	0.00	1.87	0.00	0.21	3.82
2011	1.44	0.33	0.00	1.83	0.00	0.21	3.81
2012	1.46	0.34	0.00	1.83	0.00	0.21	3.83
2013	1.49	0.34	0.00	1.80	0.00	0.21	3.83
2014	1.51	0.34	0.00	1.79	0.00	0.21	3.85
2015	1.54	0.34	0.00	1.77	0.00	0.21	3.85
2016	1.56	0.34	0.00	1.75	0.00	0.21	3.86
2017	1.59	0.34	0.00	1.73	0.00	0.21	3.87

Adopted March 18, 1998

Table I-7 (continued)

SoCal Gas Service Area
Low Price Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	Commodity	Transport	ITCS	Margin	Pitco/Popco	Regulatory	Total
1990							5.99
1991							7.34
1992							6.40
1993							6.71
1994							6.59
1995							5.85
1996							4.98
1997	2.15	0.38	0.03	1.16	0.12	0.25	4.10
1998	1.64	0.38	0.03	1.17	0.12	0.25	3.59
1999	1.13	0.37	0.03	1.16	0.12	0.25	3.06
2000	1.15	0.37	0.03	1.15	0.00	0.25	2.96
2001	1.18	0.36	0.03	1.14	0.00	0.25	2.96
2002	1.21	0.36	0.02	1.12	0.00	0.25	2.96
2003	1.24	0.35	0.02	1.12	0.00	0.25	2.99
2004	1.26	0.35	0.01	1.08	0.00	0.25	2.96
2005	1.28	0.35	0.01	1.08	0.00	0.25	2.98
2006	1.30	0.34	0.01	1.04	0.00	0.25	2.95
2007	1.34	0.33	0.00	1.03	0.00	0.25	2.95
2008	1.36	0.33	0.00	1.01	0.00	0.25	2.96
2009	1.38	0.34	0.00	1.03	0.00	0.25	3.00
2010	1.41	0.33	0.00	1.02	0.00	0.25	3.01
2011	1.44	0.33	0.00	1.00	0.00	0.25	3.02
2012	1.46	0.34	0.00	0.99	0.00	0.25	3.05
2013	1.49	0.34	0.00	0.98	0.00	0.25	3.06
2014	1.51	0.34	0.00	0.98	0.00	0.25	3.08
2015	1.54	0.34	0.00	0.96	0.00	0.25	3.09
2016	1.56	0.34	0.00	0.95	0.00	0.25	3.11
2017	1.59	0.34	0.00	0.94	0.00	0.25	3.13

Adopted March 18, 1998

Table I-8

SoCal Gas Service Area
Low Price Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.28
1991							3.91
1992							5.00
1993							4.98
1994							3.32
1995							2.39
1996							2.72
1997	2.19	0.13	0.14	0.42	0.12	0.06	3.04
1998	1.65	0.18	0.13	0.43	0.12	0.06	2.56
1999	1.16	0.19	0.10	0.43	0.12	0.06	2.04
2000	1.18	0.22	0.03	0.43	0.00	0.06	1.92
2001	1.21	0.24	0.03	0.43	0.00	0.06	1.96
2002	1.23	0.26	0.02	0.43	0.00	0.06	2.00
2003	1.26	0.27	0.02	0.43	0.00	0.06	2.03
2004	1.28	0.29	0.01	0.42	0.00	0.06	2.06
2005	1.30	0.31	0.01	0.42	0.00	0.06	2.10
2006	1.32	0.33	0.01	0.40	0.00	0.06	2.12
2007	1.34	0.40	0.00	0.40	0.00	0.06	2.19
2008	1.36	0.41	0.00	0.39	0.00	0.06	2.21
2009	1.38	0.42	0.00	0.40	0.00	0.06	2.25
2010	1.41	0.38	0.00	0.39	0.00	0.06	2.24
2011	1.43	0.39	0.00	0.39	0.00	0.06	2.26
2012	1.45	0.39	0.00	0.39	0.00	0.06	2.29
2013	1.47	0.40	0.00	0.38	0.00	0.06	2.31
2014	1.50	0.40	0.00	0.38	0.00	0.06	2.33
2015	1.52	0.40	0.00	0.38	0.00	0.06	2.36
2016	1.55	0.41	0.00	0.38	0.00	0.06	2.39
2017	1.57	0.41	0.00	0.37	0.00	0.06	2.41

Adopted March 18, 1998

Table I-8 (continued)

SoCal Gas Service Area
Low Price Case
Industrial Noncore End-Use Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.79
1991							3.64
1992							3.75
1993							3.73
1994							2.48
1995							2.29
1996							2.66
1997	2.19	0.13	0.14	0.41	0.12	0.06	3.04
1998	1.65	0.18	0.13	0.42	0.12	0.06	2.56
1999	1.16	0.19	0.10	0.43	0.12	0.06	2.04
2000	1.18	0.22	0.03	0.43	0.00	0.06	1.91
2001	1.21	0.24	0.03	0.43	0.00	0.06	1.96
2002	1.23	0.26	0.02	0.42	0.00	0.06	1.99
2003	1.26	0.27	0.02	0.42	0.00	0.06	2.03
2004	1.28	0.29	0.01	0.41	0.00	0.06	2.06
2005	1.30	0.31	0.01	0.41	0.00	0.06	2.09
2006	1.32	0.33	0.01	0.40	0.00	0.06	2.11
2007	1.34	0.40	0.00	0.39	0.00	0.06	2.18
2008	1.36	0.41	0.00	0.39	0.00	0.06	2.21
2009	1.38	0.42	0.00	0.40	0.00	0.06	2.25
2010	1.41	0.38	0.00	0.39	0.00	0.06	2.23
2011	1.43	0.39	0.00	0.38	0.00	0.06	2.26
2012	1.45	0.39	0.00	0.38	0.00	0.06	2.28
2013	1.47	0.40	0.00	0.38	0.00	0.06	2.31
2014	1.50	0.40	0.00	0.38	0.00	0.06	2.33
2015	1.52	0.40	0.00	0.38	0.00	0.06	2.35
2016	1.55	0.41	0.00	0.37	0.00	0.06	2.38
2017	1.57	0.41	0.00	0.37	0.00	0.06	2.41

Adopted March 18, 1998

Table I-8 (continued)

SoCal Gas Service Area
Low Price Case
TEOR Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.37
1991							2.86
1992							2.82
1993							3.16
1994							2.48
1995							2.01
1996							2.42
1997	2.19	0.13	0.00	0.51	0.00	0.00	2.82
1998	1.65	0.18	0.00	0.52	0.00	0.00	2.35
1999	1.16	0.19	0.00	0.53	0.00	0.00	1.87
2000	1.18	0.22	0.00	0.53	0.00	0.00	1.93
2001	1.21	0.24	0.00	0.53	0.00	0.00	1.97
2002	1.23	0.26	0.00	0.52	0.00	0.00	2.01
2003	1.26	0.27	0.00	0.52	0.00	0.00	2.05
2004	1.28	0.29	0.00	0.51	0.00	0.00	2.09
2005	1.30	0.31	0.00	0.51	0.00	0.00	2.12
2006	1.32	0.33	0.00	0.49	0.00	0.00	2.14
2007	1.34	0.40	0.00	0.48	0.00	0.00	2.22
2008	1.36	0.41	0.00	0.48	0.00	0.00	2.24
2009	1.38	0.42	0.00	0.49	0.00	0.00	2.28
2010	1.41	0.38	0.00	0.48	0.00	0.00	2.27
2011	1.43	0.39	0.00	0.47	0.00	0.00	2.29
2012	1.45	0.39	0.00	0.47	0.00	0.00	2.32
2013	1.47	0.40	0.00	0.47	0.00	0.00	2.34
2014	1.50	0.40	0.00	0.47	0.00	0.00	2.36
2015	1.52	0.40	0.00	0.46	0.00	0.00	2.39
2016	1.55	0.41	0.00	0.46	0.00	0.00	2.41
2017	1.57	0.41	0.00	0.46	0.00	0.00	2.44

Adopted March 18, 1998

Table I-9

SoCal Gas Service Area
Low Price Case
Cogen Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.67
1991							3.22
1992							3.13
1993							3.14
1994							2.65
1995							2.26
1996							2.94
1997	1.99	0.38	0.14	0.17	0.12	0.07	2.86
1998	1.64	0.21	0.13	0.18	0.12	0.06	2.34
1999	1.16	0.19	0.10	0.18	0.12	0.05	1.78
2000	1.18	0.22	0.03	0.18	0.00	0.03	1.64
2001	1.21	0.24	0.03	0.18	0.00	0.03	1.68
2002	1.23	0.26	0.02	0.18	0.00	0.03	1.72
2003	1.26	0.27	0.02	0.18	0.00	0.03	1.76
2004	1.28	0.29	0.01	0.17	0.00	0.03	1.79
2005	1.30	0.31	0.01	0.17	0.00	0.03	1.83
2006	1.32	0.33	0.01	0.17	0.00	0.03	1.85
2007	1.34	0.40	0.00	0.17	0.00	0.03	1.93
2008	1.36	0.41	0.00	0.16	0.00	0.03	1.96
2009	1.38	0.42	0.00	0.17	0.00	0.03	1.99
2010	1.41	0.38	0.00	0.16	0.00	0.03	1.98
2011	1.43	0.39	0.00	0.16	0.00	0.03	2.00
2012	1.45	0.39	0.00	0.16	0.00	0.03	2.03
2013	1.47	0.40	0.00	0.16	0.00	0.03	2.06
2014	1.50	0.40	0.00	0.16	0.00	0.03	2.08
2015	1.52	0.40	0.00	0.16	0.00	0.03	2.11
2016	1.55	0.41	0.00	0.16	0.00	0.03	2.14
2017	1.57	0.41	0.00	0.16	0.00	0.03	2.17

Adopted March 18, 1998

Table I-9 (continued)

SoCal Gas Service Area

Low Price Case

Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.67
1991							3.22
1992							3.13
1993							3.14
1994							2.65
1995							2.26
1996							2.94
1997	1.99	0.38	0.14	0.17	0.12	0.07	2.86
1998	1.64	0.21	0.13	0.18	0.12	0.06	2.34
1999	1.16	0.19	0.10	0.18	0.12	0.05	1.78
2000	1.18	0.22	0.03	0.18	0.00	0.03	1.64
2001	1.21	0.24	0.03	0.18	0.00	0.03	1.68
2002	1.23	0.26	0.02	0.18	0.00	0.03	1.72
2003	1.26	0.27	0.02	0.18	0.00	0.03	1.76
2004	1.28	0.29	0.01	0.17	0.00	0.03	1.79
2005	1.30	0.31	0.01	0.17	0.00	0.03	1.83
2006	1.32	0.33	0.01	0.17	0.00	0.03	1.85
2007	1.34	0.40	0.00	0.17	0.00	0.03	1.93
2008	1.36	0.41	0.00	0.16	0.00	0.03	1.96
2009	1.38	0.42	0.00	0.17	0.00	0.03	1.99
2010	1.41	0.38	0.00	0.16	0.00	0.03	1.98
2011	1.43	0.39	0.00	0.16	0.00	0.03	2.00
2012	1.45	0.39	0.00	0.16	0.00	0.03	2.03
2013	1.47	0.40	0.00	0.16	0.00	0.03	2.06
2014	1.50	0.40	0.00	0.16	0.00	0.03	2.08
2015	1.52	0.40	0.00	0.16	0.00	0.03	2.11
2016	1.55	0.41	0.00	0.16	0.00	0.03	2.14
2017	1.57	0.41	0.00	0.16	0.00	0.03	2.17

Adopted March 18, 1998

Table I-10

SoCal Gas Service Area
Low Price Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

Year	Commodity	Transportation Interstate	 Intrastate	Total Price
1990				3.51
1991				3.11
1992				3.00
1993				3.02
1994				2.55
1995				2.20
1996				2.85
1997	1.94	0.37	0.48	2.79
1998	1.60	0.21	0.48	2.28
1999	1.13	0.18	0.43	1.74
2000	1.15	0.21	0.23	1.60
2001	1.18	0.24	0.23	1.64
2002	1.20	0.25	0.22	1.68
2003	1.23	0.26	0.22	1.71
2004	1.25	0.29	0.21	1.75
2005	1.27	0.30	0.21	1.78
2006	1.29	0.32	0.20	1.81
2007	1.31	0.39	0.19	1.88
2008	1.33	0.40	0.19	1.91
2009	1.35	0.41	0.19	1.94
2010	1.37	0.37	0.19	1.93
2011	1.39	0.38	0.18	1.95
2012	1.42	0.38	0.18	1.98
2013	1.44	0.39	0.18	2.01
2014	1.46	0.39	0.18	2.03
2015	1.48	0.39	0.18	2.06
2016	1.51	0.40	0.18	2.09
2017	1.53	0.40	0.18	2.11

Adopted March 18, 1998

Table I-10 (continued)

SoCal Gas Service Area
Low Price Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Electricity Generation				Cogen Gas Price
		Transportation			
Year	**Commodity**	**Interstate**	**Intrastate**	**Total Price**	
1990				3.05	3.05
1991				2.81	2.81
1992				2.79	2.79
1993				2.88	2.88
1994				2.49	2.49
1995				2.20	2.20
1996				2.91	2.91
1997	2.02	0.38	0.50	2.90	2.90
1998	1.70	0.22	0.51	2.43	2.43
1999	1.23	0.20	0.47	1.90	1.90
2000	1.29	0.24	0.26	1.79	1.79
2001	1.35	0.27	0.26	1.89	1.89
2002	1.43	0.30	0.26	1.98	1.98
2003	1.50	0.32	0.27	2.09	2.09
2004	1.58	0.36	0.26	2.20	2.20
2005	1.65	0.39	0.27	2.32	2.32
2006	1.74	0.43	0.27	2.44	2.44
2007	1.82	0.54	0.26	2.62	2.62
2008	1.91	0.57	0.27	2.75	2.75
2009	2.01	0.61	0.28	2.90	2.90
2010	2.12	0.58	0.29	2.99	2.99
2011	2.24	0.60	0.30	3.14	3.14
2012	2.35	0.63	0.31	3.29	3.29
2013	2.47	0.66	0.31	3.45	3.45
2014	2.60	0.69	0.32	3.62	3.62
2015	2.74	0.73	0.33	3.80	3.80
2016	2.89	0.76	0.34	3.99	3.99
2017	3.04	0.80	0.35	4.19	4.19

Adopted March 18, 1998

Table I-11

SDG&E Service Area
Low Price Case
End-Use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.43	6.61	6.40	4.41	4.41	0.00	3.71	3.71	5.06
1991	6.05	6.13	6.13	3.88	3.88	0.00	3.25	3.25	4.61
1992	6.45	6.67	6.67	4.02	4.02	0.00	3.20	3.20	4.71
1993	6.85	6.87	6.44	3.81	3.96	0.00	3.33	3.33	4.97
1994	6.89	6.71	5.53	3.60	3.90	0.00	3.04	3.04	4.88
1995	6.44	6.32	5.31	2.71	2.74	0.00	2.18	2.18	4.01
1996	6.65	6.24	5.00	3.00	3.02	0.00	2.53	2.53	4.40
1997	6.86	6.16	4.70	3.30	3.30	0.00	3.05	3.05	4.54
1998	6.35	5.66	4.21	2.81	2.81	0.00	2.63	2.63	4.05
1999	5.92	5.22	3.76	2.29	2.29	0.00	2.07	2.07	3.65
2000	5.93	5.24	3.79	2.26	2.26	0.00	2.05	2.05	3.61
2001	5.97	5.28	3.83	2.30	2.30	0.00	2.09	2.08	3.65
2002	5.78	5.11	3.74	2.33	2.33	0.00	2.12	2.11	3.32
2003	5.83	5.16	3.78	2.36	2.36	0.00	2.13	2.13	3.41
2004	5.77	5.12	3.77	2.38	2.38	0.00	2.16	2.16	3.36
2005	5.78	5.13	3.78	2.40	2.40	0.00	2.18	2.18	3.42
2006	5.70	5.06	3.75	2.41	2.41	0.00	2.20	2.20	3.35
2007	5.67	5.05	3.77	2.47	2.47	0.00	2.26	2.25	3.34
2008	5.62	5.00	3.76	2.48	2.48	0.00	2.28	2.27	3.32
2009	5.61	5.00	3.77	2.50	2.50	0.00	2.30	2.29	3.37
2010	5.55	4.95	3.73	2.48	2.48	0.00	2.29	2.28	3.35
2011	5.50	4.91	3.72	2.50	2.50	0.00	2.31	2.30	3.32
2012	5.48	4.89	3.72	2.52	2.52	0.00	2.32	2.32	3.33
2013	5.44	4.86	3.71	2.53	2.53	0.00	2.34	2.34	3.32
2014	5.42	4.85	3.71	2.55	2.55	0.00	2.36	2.36	3.32
2015	5.41	4.85	3.72	2.57	2.57	0.00	2.38	2.38	3.36
2016	5.41	4.84	3.74	2.60	2.60	0.00	2.42	2.41	3.38
2017	5.39	4.83	3.74	2.62	2.62	0.00	2.44	2.44	3.39

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7; 1996 is interpolated.
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- SDG&E Margin: Distribution and administration costs associated with running the SDG&E pipeline system and transmission charges to SoCal Gas.
- PITCO/POPCO: Global settlement associated with PITCO and POPCO long term supply contracts.
- Regulatory: Includes balancing accounts, social, environmental, and other regulatory accounts.

Adopted March 18, 1998

Table I-12

SDG&E Service Area
Low Price Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.43
1991							6.05
1992							6.45
1993							6.85
1994							6.89
1995							6.44
1996							6.65
1997	2.08	0.23	0.03	4.24	0.00	0.27	6.86
1998	1.58	0.26	0.03	4.21	0.00	0.27	6.35
1999	1.11	0.27	0.03	4.24	0.00	0.27	5.92
2000	1.13	0.29	0.03	4.21	0.00	0.27	5.93
2001	1.15	0.31	0.03	4.21	0.00	0.27	5.97
2002	1.19	0.30	0.02	3.99	0.00	0.27	5.78
2003	1.22	0.32	0.02	4.00	0.00	0.27	5.83
2004	1.24	0.33	0.01	3.91	0.00	0.27	5.77
2005	1.26	0.35	0.01	3.89	0.00	0.27	5.78
2006	1.28	0.36	0.01	3.78	0.00	0.27	5.70
2007	1.30	0.41	0.00	3.69	0.00	0.27	5.67
2008	1.32	0.42	0.00	3.60	0.00	0.27	5.62
2009	1.34	0.43	0.00	3.57	0.00	0.27	5.61
2010	1.36	0.40	0.00	3.51	0.00	0.27	5.55
2011	1.39	0.41	0.00	3.44	0.00	0.27	5.50
2012	1.41	0.41	0.00	3.39	0.00	0.27	5.48
2013	1.43	0.42	0.00	3.32	0.00	0.27	5.44
2014	1.45	0.42	0.00	3.28	0.00	0.27	5.42
2015	1.47	0.42	0.00	3.24	0.00	0.27	5.41
2016	1.51	0.43	0.00	3.20	0.00	0.27	5.41
2017	1.53	0.43	0.00	3.15	0.00	0.27	5.39

Adopted March 18, 1998

Table I-12 (continued)

SDG&E Service Area
Low Price Case
Commercial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.61
1991							6.13
1992							6.67
1993							6.87
1994							6.71
1995							6.32
1996							6.24
1997	2.08	0.23	0.03	3.70	0.00	0.12	6.16
1998	1.58	0.26	0.03	3.67	0.00	0.12	5.66
1999	1.11	0.27	0.03	3.69	0.00	0.12	5.22
2000	1.13	0.29	0.03	3.67	0.00	0.12	5.24
2001	1.15	0.31	0.03	3.67	0.00	0.12	5.28
2002	1.19	0.30	0.02	3.48	0.00	0.12	5.11
2003	1.22	0.32	0.02	3.49	0.00	0.12	5.16
2004	1.24	0.33	0.01	3.41	0.00	0.12	5.12
2005	1.26	0.35	0.01	3.39	0.00	0.12	5.13
2006	1.28	0.36	0.01	3.29	0.00	0.12	5.06
2007	1.30	0.41	0.00	3.22	0.00	0.12	5.05
2008	1.32	0.42	0.00	3.14	0.00	0.12	5.00
2009	1.34	0.43	0.00	3.11	0.00	0.12	5.00
2010	1.36	0.40	0.00	3.06	0.00	0.12	4.95
2011	1.39	0.41	0.00	3.00	0.00	0.12	4.91
2012	1.41	0.41	0.00	2.95	0.00	0.12	4.89
2013	1.43	0.42	0.00	2.90	0.00	0.12	4.86
2014	1.45	0.42	0.00	2.86	0.00	0.12	4.85
2015	1.47	0.42	0.00	2.83	0.00	0.12	4.85
2016	1.51	0.43	0.00	2.79	0.00	0.12	4.84
2017	1.53	0.43	0.00	2.75	0.00	0.12	4.83

Adopted March 18, 1998

Table I-12 (continued)

SDG&E Service Area
Low Price Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.40
1991							6.13
1992							6.67
1993							6.44
1994							5.53
1995							5.31
1996							5.00
1997	2.08	0.23	0.03	2.23	0.00	0.12	4.70
1998	1.58	0.26	0.03	2.21	0.00	0.12	4.21
1999	1.11	0.27	0.03	2.23	0.00	0.12	3.76
2000	1.13	0.29	0.03	2.21	0.00	0.12	3.79
2001	1.15	0.31	0.03	2.22	0.00	0.12	3.83
2002	1.19	0.30	0.02	2.10	0.00	0.12	3.74
2003	1.22	0.32	0.02	2.10	0.00	0.12	3.78
2004	1.24	0.33	0.01	2.06	0.00	0.12	3.77
2005	1.26	0.35	0.01	2.05	0.00	0.12	3.78
2006	1.28	0.36	0.01	1.99	0.00	0.12	3.75
2007	1.30	0.41	0.00	1.94	0.00	0.12	3.77
2008	1.32	0.42	0.00	1.90	0.00	0.12	3.76
2009	1.34	0.43	0.00	1.88	0.00	0.12	3.77
2010	1.36	0.40	0.00	1.85	0.00	0.12	3.73
2011	1.39	0.41	0.00	1.81	0.00	0.12	3.72
2012	1.41	0.41	0.00	1.78	0.00	0.12	3.72
2013	1.43	0.42	0.00	1.75	0.00	0.12	3.71
2014	1.45	0.42	0.00	1.73	0.00	0.12	3.71
2015	1.47	0.42	0.00	1.71	0.00	0.12	3.72
2016	1.51	0.43	0.00	1.69	0.00	0.12	3.74
2017	1.53	0.43	0.00	1.66	0.00	0.12	3.74

Adopted March 18, 1998

Table I-13

SDG&E Service Area
Low Price Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.41
1991							3.88
1992							4.02
1993							3.81
1994							3.60
1995							2.71
1996							3.00
1997	2.08	0.23	0.15	0.81	0.00	0.03	3.30
1998	1.58	0.26	0.14	0.79	0.00	0.03	2.81
1999	1.11	0.27	0.10	0.78	0.00	0.03	2.29
2000	1.13	0.29	0.03	0.78	0.00	0.03	2.26
2001	1.15	0.31	0.03	0.78	0.00	0.03	2.30
2002	1.19	0.30	0.02	0.78	0.00	0.03	2.33
2003	1.22	0.32	0.02	0.77	0.00	0.03	2.36
2004	1.24	0.33	0.01	0.76	0.00	0.03	2.38
2005	1.26	0.35	0.01	0.75	0.00	0.03	2.40
2006	1.28	0.36	0.01	0.74	0.00	0.03	2.41
2007	1.30	0.41	0.00	0.72	0.00	0.03	2.47
2008	1.32	0.42	0.00	0.71	0.00	0.03	2.48
2009	1.34	0.43	0.00	0.70	0.00	0.03	2.50
2010	1.36	0.40	0.00	0.69	0.00	0.03	2.48
2011	1.39	0.41	0.00	0.68	0.00	0.03	2.50
2012	1.41	0.41	0.00	0.67	0.00	0.03	2.52
2013	1.43	0.42	0.00	0.66	0.00	0.03	2.53
2014	1.45	0.42	0.00	0.65	0.00	0.03	2.55
2015	1.47	0.42	0.00	0.64	0.00	0.03	2.57
2016	1.51	0.43	0.00	0.63	0.00	0.03	2.60
2017	1.53	0.43	0.00	0.62	0.00	0.03	2.62

Adopted March 18, 1998

Table I-13 (continued)
SDG&E Service Area
Low Price Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.41
1991							3.88
1992							4.02
1993							3.96
1994							3.90
1995							2.74
1996							3.02
1997	2.08	0.23	0.15	0.81	0.00	0.03	3.30
1998	1.58	0.26	0.14	0.79	0.00	0.03	2.81
1999	1.11	0.27	0.10	0.78	0.00	0.03	2.29
2000	1.13	0.29	0.03	0.78	0.00	0.03	2.26
2001	1.15	0.31	0.03	0.78	0.00	0.03	2.30
2002	1.19	0.30	0.02	0.78	0.00	0.03	2.33
2003	1.22	0.32	0.02	0.77	0.00	0.03	2.36
2004	1.24	0.33	0.01	0.76	0.00	0.03	2.38
2005	1.26	0.35	0.01	0.75	0.00	0.03	2.40
2006	1.28	0.36	0.01	0.74	0.00	0.03	2.41
2007	1.30	0.41	0.00	0.72	0.00	0.03	2.47
2008	1.32	0.42	0.00	0.71	0.00	0.03	2.48
2009	1.34	0.43	0.00	0.70	0.00	0.03	2.50
2010	1.36	0.40	0.00	0.69	0.00	0.03	2.48
2011	1.39	0.41	0.00	0.68	0.00	0.03	2.50
2012	1.41	0.41	0.00	0.67	0.00	0.03	2.52
2013	1.43	0.42	0.00	0.66	0.00	0.03	2.53
2014	1.45	0.42	0.00	0.65	0.00	0.03	2.55
2015	1.47	0.42	0.00	0.64	0.00	0.03	2.57
2016	1.51	0.43	0.00	0.63	0.00	0.03	2.60
2017	1.53	0.43	0.00	0.62	0.00	0.03	2.62

Adopted March 18, 1998

Table I-14

SDG&E Service Area
Low Price Case
Cogen Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	2.08	0.23	0.15	0.49	0.00	0.10	3.05
1998	1.58	0.26	0.14	0.54	0.00	0.10	2.63
1999	1.11	0.27	0.10	0.49	0.00	0.10	2.07
2000	1.13	0.29	0.03	0.50	0.00	0.10	2.05
2001	1.15	0.31	0.03	0.50	0.00	0.10	2.09
2002	1.19	0.30	0.02	0.49	0.00	0.10	2.12
2003	1.22	0.32	0.02	0.47	0.00	0.10	2.13
2004	1.24	0.33	0.01	0.47	0.00	0.10	2.16
2005	1.26	0.35	0.01	0.46	0.00	0.10	2.18
2006	1.28	0.36	0.01	0.45	0.00	0.10	2.20
2007	1.30	0.41	0.00	0.44	0.00	0.10	2.26
2008	1.32	0.42	0.00	0.43	0.00	0.10	2.28
2009	1.34	0.43	0.00	0.42	0.00	0.10	2.30
2010	1.36	0.40	0.00	0.42	0.00	0.10	2.29
2011	1.39	0.41	0.00	0.41	0.00	0.10	2.31
2012	1.41	0.41	0.00	0.40	0.00	0.10	2.32
2013	1.43	0.42	0.00	0.40	0.00	0.10	2.34
2014	1.45	0.42	0.00	0.39	0.00	0.10	2.36
2015	1.47	0.42	0.00	0.39	0.00	0.10	2.38
2016	1.51	0.43	0.00	0.38	0.00	0.10	2.42
2017	1.53	0.43	0.00	0.38	0.00	0.10	2.44

Adopted March 18, 1998

Table I-14 (continued)

SDG&E Service Area
Low Price Case
Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	2.08	0.23	0.15	0.49	0.00	0.10	3.05
1998	1.58	0.26	0.14	0.54	0.00	0.10	2.63
1999	1.11	0.27	0.10	0.49	0.00	0.10	2.07
2000	1.13	0.29	0.03	0.50	0.00	0.10	2.05
2001	1.15	0.31	0.03	0.50	0.00	0.10	2.08
2002	1.19	0.30	0.02	0.49	0.00	0.10	2.11
2003	1.22	0.32	0.02	0.47	0.00	0.10	2.13
2004	1.24	0.33	0.01	0.47	0.00	0.10	2.16
2005	1.26	0.35	0.01	0.46	0.00	0.10	2.18
2006	1.28	0.36	0.01	0.45	0.00	0.10	2.20
2007	1.30	0.41	0.00	0.44	0.00	0.10	2.25
2008	1.32	0.42	0.00	0.43	0.00	0.10	2.27
2009	1.34	0.43	0.00	0.42	0.00	0.10	2.29
2010	1.36	0.40	0.00	0.42	0.00	0.10	2.28
2011	1.39	0.41	0.00	0.41	0.00	0.10	2.30
2012	1.41	0.41	0.00	0.40	0.00	0.10	2.32
2013	1.43	0.42	0.00	0.40	0.00	0.10	2.34
2014	1.45	0.42	0.00	0.39	0.00	0.10	2.36
2015	1.47	0.42	0.00	0.39	0.00	0.10	2.38
2016	1.51	0.43	0.00	0.38	0.00	0.10	2.41
2017	1.53	0.43	0.00	0.38	0.00	0.10	2.44

Adopted March 18, 1998

Table I-15

SDG&E Service Area
Low Price Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

		Transportation		Total
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**
1990			2.11	3.60
1991			2.03	3.16
1992			2.10	3.10
1993			2.12	3.24
1994			2.09	2.98
1995			2.09	2.14
1996			1.39	2.50
1997	2.03	0.22	0.72	2.98
1998	1.54	0.26	0.77	2.56
1999	1.08	0.26	0.68	2.02
2000	1.10	0.28	0.62	2.00
2001	1.13	0.30	0.61	2.03
2002	1.16	0.30	0.60	2.06
2003	1.19	0.31	0.58	2.08
2004	1.21	0.33	0.57	2.10
2005	1.23	0.34	0.56	2.13
2006	1.25	0.35	0.55	2.14
2007	1.26	0.40	0.53	2.20
2008	1.29	0.41	0.52	2.22
2009	1.31	0.42	0.51	2.24
2010	1.33	0.39	0.51	2.23
2011	1.35	0.40	0.50	2.25
2012	1.37	0.40	0.49	2.26
2013	1.39	0.41	0.48	2.28
2014	1.41	0.41	0.48	2.30
2015	1.44	0.41	0.47	2.32
2016	1.47	0.42	0.47	2.35
2017	1.49	0.42	0.46	2.38

Adopted March 18, 1998

Table I-15 (continued)

SDG&E Service Area
Low Price Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Electricity Generation				Cogen
		Transportation		Total	Gas
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990			1.84	3.13	3.13
1991			1.83	2.86	2.86
1992			1.95	2.88	2.88
1993			2.02	3.09	3.09
1994			2.04	2.90	2.90
1995			2.09	2.14	2.14
1996			1.42	2.55	2.55
1997	2.11	0.23	0.75	3.09	3.09
1998	1.64	0.27	0.82	2.72	2.72
1999	1.18	0.28	0.74	2.20	2.20
2000	1.23	0.32	0.69	2.24	2.24
2001	1.30	0.34	0.70	2.34	2.34
2002	1.38	0.35	0.71	2.44	2.44
2003	1.45	0.38	0.71	2.53	2.53
2004	1.52	0.41	0.72	2.65	2.65
2005	1.60	0.44	0.73	2.77	2.77
2006	1.68	0.47	0.74	2.89	2.89
2007	1.76	0.56	0.74	3.06	3.06
2008	1.86	0.60	0.75	3.20	3.20
2009	1.95	0.63	0.76	3.35	3.35
2010	2.06	0.61	0.78	3.45	3.45
2011	2.17	0.64	0.80	3.60	3.60
2012	2.28	0.67	0.82	3.76	3.76
2013	2.40	0.70	0.83	3.93	3.93
2014	2.52	0.73	0.85	4.10	4.10
2015	2.65	0.76	0.87	4.29	4.29
2016	2.81	0.79	0.90	4.50	4.50
2017	2.96	0.83	0.92	4.71	4.71

Adopted March 18, 1998

APPENDIX J
HIGH NATURAL GAS PRICE FORECAST

The High Price Forecast was prepared by the California Energy Commission for the ***Fuels Report*** to analyze the impacts of natural gas price uncertainty. It is a higher extreme that is possible under the assumptions made, but not sustainable. As such, the High Price Forecast represents a higher bound to the Basecase forecast. In these tables, the natural gas price forecast for electricity generation has been converted to current $/mmbtu.

Table J-1

PG&E Service Area
High Price Case
End-use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.42	6.33	5.59	3.63	3.94	2.93	3.65	3.65	4.40
1991	6.44	6.44	5.64	2.99	3.14	3.47	3.15	3.15	4.25
1992	6.20	6.77	5.04	2.89	2.31	2.72	2.87	2.87	4.51
1993	5.92	6.28	4.97	3.10	2.30	2.43	3.10	3.10	3.69
1994	6.11	6.32	4.65	3.02	2.06	2.05	2.32	2.32	3.62
1995	6.35	6.41	4.67	2.52	1.85	1.52	2.24	2.24	3.57
1996	6.73	6.76	4.68	2.99	2.33	2.06	2.36	2.36	4.07
1997	7.12	7.11	4.68	3.47	2.82	2.60	2.68	2.68	4.28
1998	6.95	7.52	4.42	3.67	2.68	2.60	2.62	2.62	4.15
1999	6.69	6.68	3.85	3.52	2.57	2.49	2.51	2.51	3.86
2000	6.46	6.45	3.81	3.42	2.48	2.41	2.42	2.42	3.68
2001	6.30	6.29	3.83	3.44	2.52	2.47	2.47	2.47	3.67
2002	6.14	6.13	3.85	3.47	2.57	2.52	2.52	2.52	3.64
2003	6.13	6.12	3.87	3.51	2.62	2.57	2.57	2.57	3.65
2004	6.14	6.13	3.91	3.55	2.67	2.63	2.62	2.62	3.70
2005	6.14	6.14	3.94	3.59	2.73	2.68	2.68	2.68	3.73
2006	6.12	6.12	3.96	3.65	2.79	2.75	2.73	2.73	3.73
2007	6.14	6.13	3.99	3.70	2.84	2.81	2.79	2.79	3.79
2008	6.11	6.11	4.01	3.73	2.89	2.86	2.84	2.84	3.80
2009	6.15	6.14	4.05	3.79	2.95	2.92	2.90	2.90	3.84
2010	6.17	6.17	4.10	3.83	3.00	2.98	2.95	2.95	3.90
2011	6.20	6.20	4.15	3.88	3.06	3.03	3.01	3.01	3.96
2012	6.22	6.22	4.19	3.94	3.12	3.09	3.07	3.07	3.99
2013	6.25	6.25	4.25	3.99	3.18	3.15	3.13	3.13	4.06
2014	6.28	6.28	4.30	4.04	3.24	3.21	3.19	3.19	4.11
2015	6.30	6.31	4.34	4.09	3.30	3.26	3.25	3.25	4.16
2016	6.35	6.35	4.39	4.15	3.35	3.32	3.30	3.30	4.22
2017	6.38	6.38	4.44	4.20	3.41	3.38	3.36	3.36	4.28

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7.
- 1997 margin based on PG&E Advice No. 1978-G, November 15, 1998.
- Remaining years margin based on PG&E Revised BCAP Application No. 97-03-002 and associated work papers (Aug. 18 and 27, 1997).
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border; fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- PG&E Margin: Includes base margin, access charges, portion of the backbone costs, local transmission, and core storage.
- PG&E Backbone: Weighted average transmission charge to transport natural gas on Line 300, phased in Line 400/401, and incremental Line 401.
- Regulatory: Instate charge to recover customer class charges, including balancing accounts, social, environmental, and other regulatory accounts.

Adopted March 18, 1998

Table J-2

PG&E Service Area
High Price Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							6.42
1991							6.44
1992							6.20
1993							5.92
1994							6.11
1995							6.35
1996							6.73
1997	1.71	0.46	0.04	4.43	0.00	0.49	7.12
1998	1.66	0.46	0.04	3.92	0.12	0.74	6.95
1999	1.64	0.47	0.04	3.83	0.12	0.58	6.69
2000	1.69	0.47	0.00	3.76	0.12	0.43	6.46
2001	1.74	0.47	0.00	3.70	0.12	0.27	6.30
2002	1.79	0.47	0.00	3.64	0.12	0.12	6.14
2003	1.84	0.47	0.00	3.59	0.12	0.12	6.13
2004	1.88	0.47	0.00	3.55	0.12	0.12	6.14
2005	1.93	0.47	0.00	3.51	0.12	0.12	6.14
2006	1.98	0.47	0.00	3.44	0.12	0.12	6.12
2007	2.02	0.47	0.00	3.42	0.12	0.12	6.14
2008	2.07	0.47	0.00	3.34	0.12	0.12	6.11
2009	2.12	0.47	0.00	3.33	0.12	0.12	6.15
2010	2.18	0.47	0.00	3.29	0.12	0.12	6.17
2011	2.24	0.47	0.00	3.26	0.12	0.12	6.20
2012	2.30	0.47	0.00	3.21	0.12	0.12	6.22
2013	2.36	0.47	0.00	3.19	0.12	0.12	6.25
2014	2.42	0.47	0.00	3.16	0.12	0.12	6.28
2015	2.48	0.47	0.00	3.12	0.12	0.12	6.30
2016	2.53	0.47	0.00	3.11	0.12	0.12	6.35
2017	2.59	0.47	0.00	3.08	0.12	0.12	6.38

Adopted March 18, 1998

Table J-2 (continued)

PG&E Service Area
High Price Case
Commercial Core Natural Gas Price Forecast by Sector

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							6.33
1991							6.44
1992							6.77
1993							6.28
1994							6.32
1995							6.41
1996							6.76
1997	1.71	0.46	0.04	4.43	0.00	0.48	7.11
1998	1.66	0.46	0.04	4.43	0.12	0.80	7.52
1999	1.64	0.47	0.04	3.76	0.12	0.64	6.68
2000	1.69	0.47	0.00	3.69	0.12	0.49	6.45
2001	1.74	0.47	0.00	3.63	0.12	0.33	6.29
2002	1.79	0.47	0.00	3.58	0.12	0.18	6.13
2003	1.84	0.47	0.00	3.52	0.12	0.18	6.12
2004	1.88	0.47	0.00	3.49	0.12	0.18	6.13
2005	1.93	0.47	0.00	3.44	0.12	0.18	6.14
2006	1.98	0.47	0.00	3.38	0.12	0.18	6.12
2007	2.02	0.47	0.00	3.36	0.12	0.18	6.13
2008	2.07	0.47	0.00	3.28	0.12	0.18	6.11
2009	2.12	0.47	0.00	3.27	0.12	0.18	6.14
2010	2.18	0.47	0.00	3.23	0.12	0.18	6.17
2011	2.24	0.47	0.00	3.20	0.12	0.18	6.20
2012	2.30	0.47	0.00	3.15	0.12	0.18	6.22
2013	2.36	0.47	0.00	3.13	0.12	0.18	6.25
2014	2.42	0.47	0.00	3.10	0.12	0.18	6.28
2015	2.48	0.47	0.00	3.06	0.12	0.18	6.31
2016	2.53	0.47	0.00	3.05	0.12	0.18	6.35
2017	2.59	0.47	0.00	3.03	0.12	0.18	6.38

Adopted March 18, 1998

Table J-2 (continued)

PG&E Service Area
High Price Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							5.59
1991							5.64
1992							5.04
1993							4.97
1994							4.65
1995							4.67
1996							4.68
1997	1.71	0.46	0.04	2.40	0.00	0.08	4.68
1998	1.66	0.46	0.04	2.00	0.12	0.12	4.42
1999	1.64	0.47	0.04	1.46	0.12	0.11	3.85
2000	1.69	0.47	0.00	1.43	0.12	0.10	3.81
2001	1.74	0.47	0.00	1.41	0.12	0.09	3.83
2002	1.79	0.47	0.00	1.39	0.12	0.08	3.85
2003	1.84	0.47	0.00	1.37	0.12	0.08	3.87
2004	1.88	0.47	0.00	1.36	0.12	0.08	3.91
2005	1.93	0.47	0.00	1.34	0.12	0.08	3.94
2006	1.98	0.47	0.00	1.31	0.12	0.08	3.96
2007	2.02	0.47	0.00	1.30	0.12	0.08	3.99
2008	2.07	0.47	0.00	1.28	0.12	0.08	4.01
2009	2.12	0.47	0.00	1.27	0.12	0.08	4.05
2010	2.18	0.47	0.00	1.26	0.12	0.08	4.10
2011	2.24	0.47	0.00	1.24	0.12	0.08	4.15
2012	2.30	0.47	0.00	1.23	0.12	0.08	4.19
2013	2.36	0.47	0.00	1.22	0.12	0.08	4.25
2014	2.42	0.47	0.00	1.20	0.12	0.08	4.30
2015	2.48	0.47	0.00	1.19	0.12	0.08	4.34
2016	2.53	0.47	0.00	1.19	0.12	0.08	4.39
2017	2.59	0.47	0.00	1.18	0.12	0.08	4.44

Adopted March 18, 1998

Table J-3

PG&E Service Area
High Price Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.63
1991							2.99
1992							2.89
1993							3.10
1994							3.02
1995							2.52
1996							2.99
1997	1.79	0.22	0.10	1.28	0.00	0.08	3.47
1998	1.72	0.30	0.14	1.19	0.18	0.14	3.67
1999	1.62	0.31	0.14	1.15	0.18	0.13	3.52
2000	1.67	0.33	0.00	1.13	0.17	0.12	3.42
2001	1.71	0.34	0.00	1.11	0.17	0.11	3.44
2002	1.76	0.36	0.00	1.09	0.17	0.10	3.47
2003	1.80	0.38	0.00	1.07	0.16	0.10	3.51
2004	1.84	0.40	0.00	1.05	0.16	0.10	3.55
2005	1.89	0.41	0.00	1.04	0.15	0.10	3.59
2006	1.93	0.43	0.00	1.04	0.15	0.10	3.65
2007	1.97	0.46	0.00	1.02	0.14	0.10	3.70
2008	2.02	0.47	0.00	1.00	0.14	0.10	3.73
2009	2.06	0.49	0.00	1.01	0.13	0.10	3.79
2010	2.17	0.45	0.00	0.99	0.13	0.10	3.83
2011	2.22	0.45	0.00	0.99	0.13	0.10	3.88
2012	2.28	0.46	0.00	0.98	0.13	0.10	3.94
2013	2.33	0.46	0.00	0.97	0.13	0.10	3.99
2014	2.39	0.46	0.00	0.96	0.13	0.10	4.04
2015	2.44	0.47	0.00	0.96	0.13	0.10	4.09
2016	2.49	0.48	0.00	0.96	0.13	0.10	4.15
2017	2.54	0.49	0.00	0.95	0.13	0.10	4.20

Adopted March 18, 1998

Table J-3 (continued)

PG&E Service Area
High Price Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.94
1991							3.14
1992							2.31
1993							2.30
1994							2.06
1995							1.85
1996							2.33
1997	1.79	0.22	0.10	0.63	0.00	0.08	2.82
1998	1.72	0.30	0.14	0.22	0.18	0.12	2.68
1999	1.62	0.31	0.14	0.21	0.18	0.11	2.57
2000	1.67	0.33	0.00	0.21	0.17	0.10	2.48
2001	1.71	0.34	0.00	0.20	0.17	0.09	2.52
2002	1.76	0.36	0.00	0.20	0.17	0.08	2.57
2003	1.80	0.38	0.00	0.20	0.16	0.08	2.62
2004	1.84	0.40	0.00	0.19	0.16	0.08	2.67
2005	1.89	0.41	0.00	0.19	0.15	0.08	2.73
2006	1.93	0.43	0.00	0.19	0.15	0.08	2.79
2007	1.97	0.46	0.00	0.19	0.14	0.08	2.84
2008	2.02	0.47	0.00	0.18	0.14	0.08	2.89
2009	2.06	0.49	0.00	0.18	0.13	0.08	2.95
2010	2.17	0.45	0.00	0.18	0.13	0.08	3.00
2011	2.22	0.45	0.00	0.18	0.13	0.08	3.06
2012	2.28	0.46	0.00	0.18	0.13	0.08	3.12
2013	2.33	0.46	0.00	0.18	0.13	0.08	3.18
2014	2.39	0.46	0.00	0.18	0.13	0.08	3.24
2015	2.44	0.47	0.00	0.18	0.13	0.08	3.30
2016	2.49	0.48	0.00	0.17	0.13	0.08	3.35
2017	2.54	0.49	0.00	0.17	0.13	0.08	3.41

Adopted March 18, 1998

Table J-3 (continued)

PG&E Service Area
High Price Case
TEOR Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							2.93
1991							3.47
1992							2.72
1993							2.43
1994							2.05
1995							1.52
1996							2.06
1997	1.79	0.22	0.10	0.49	0.00	0.00	2.60
1998	1.72	0.30	0.14	0.44	0.00	0.00	2.60
1999	1.62	0.31	0.14	0.42	0.00	0.00	2.49
2000	1.67	0.33	0.00	0.42	0.00	0.00	2.41
2001	1.71	0.34	0.00	0.41	0.00	0.00	2.47
2002	1.76	0.36	0.00	0.40	0.00	0.00	2.52
2003	1.80	0.38	0.00	0.39	0.00	0.00	2.57
2004	1.84	0.40	0.00	0.39	0.00	0.00	2.63
2005	1.89	0.41	0.00	0.38	0.00	0.00	2.68
2006	1.93	0.43	0.00	0.38	0.00	0.00	2.75
2007	1.97	0.46	0.00	0.38	0.00	0.00	2.81
2008	2.02	0.47	0.00	0.37	0.00	0.00	2.86
2009	2.06	0.49	0.00	0.37	0.00	0.00	2.92
2010	2.17	0.45	0.00	0.37	0.00	0.00	2.98
2011	2.22	0.45	0.00	0.36	0.00	0.00	3.03
2012	2.28	0.46	0.00	0.36	0.00	0.00	3.09
2013	2.33	0.46	0.00	0.36	0.00	0.00	3.15
2014	2.39	0.46	0.00	0.35	0.00	0.00	3.21
2015	2.44	0.47	0.00	0.35	0.00	0.00	3.26
2016	2.49	0.48	0.00	0.35	0.00	0.00	3.32
2017	2.54	0.49	0.00	0.35	0.00	0.00	3.38

Adopted March 18, 1998

Table J-4

PG&E Service Area
High Price Case
Cogen Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	Commodity	Transport	ITCS	Margin	Backbone	Regulatory	Total
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	1.82	0.24	0.10	0.49	0.00	0.03	2.68
1998	1.74	0.31	0.14	0.19	0.18	0.07	2.62
1999	1.64	0.31	0.14	0.19	0.17	0.06	2.51
2000	1.69	0.33	0.00	0.18	0.17	0.06	2.42
2001	1.73	0.34	0.00	0.18	0.17	0.05	2.47
2002	1.78	0.36	0.00	0.18	0.16	0.04	2.52
2003	1.82	0.37	0.00	0.17	0.16	0.04	2.57
2004	1.86	0.39	0.00	0.17	0.16	0.04	2.62
2005	1.91	0.41	0.00	0.17	0.15	0.04	2.68
2006	1.95	0.43	0.00	0.17	0.15	0.04	2.73
2007	1.99	0.45	0.00	0.17	0.14	0.04	2.79
2008	2.04	0.46	0.00	0.16	0.14	0.04	2.84
2009	2.08	0.48	0.00	0.16	0.13	0.04	2.90
2010	2.18	0.44	0.00	0.16	0.13	0.04	2.95
2011	2.24	0.44	0.00	0.16	0.13	0.04	3.01
2012	2.30	0.45	0.00	0.16	0.13	0.04	3.07
2013	2.35	0.45	0.00	0.16	0.13	0.04	3.13
2014	2.41	0.46	0.00	0.16	0.13	0.04	3.19
2015	2.46	0.46	0.00	0.16	0.13	0.04	3.25
2016	2.51	0.47	0.00	0.16	0.13	0.04	3.30
2017	2.56	0.48	0.00	0.15	0.13	0.04	3.36

Adopted March 18, 1998

Table J-4 (continued)

PG&E Service Area
High Price Case
Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		PG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Backbone**	**Regulatory**	**Total**
1990							3.65
1991							3.15
1992							2.87
1993							3.10
1994							2.32
1995							2.24
1996							2.36
1997	1.82	0.24	0.10	0.49	0.00	0.03	2.68
1998	1.74	0.31	0.14	0.19	0.18	0.07	2.62
1999	1.64	0.31	0.14	0.19	0.17	0.06	2.51
2000	1.69	0.33	0.00	0.18	0.17	0.06	2.42
2001	1.73	0.34	0.00	0.18	0.17	0.05	2.47
2002	1.78	0.36	0.00	0.18	0.16	0.04	2.52
2003	1.82	0.37	0.00	0.17	0.16	0.04	2.57
2004	1.86	0.39	0.00	0.17	0.16	0.04	2.62
2005	1.91	0.41	0.00	0.17	0.15	0.04	2.68
2006	1.95	0.43	0.00	0.17	0.15	0.04	2.73
2007	1.99	0.45	0.00	0.17	0.14	0.04	2.79
2008	2.04	0.46	0.00	0.16	0.14	0.04	2.84
2009	2.08	0.48	0.00	0.16	0.13	0.04	2.90
2010	2.18	0.44	0.00	0.16	0.13	0.04	2.95
2011	2.24	0.44	0.00	0.16	0.13	0.04	3.01
2012	2.30	0.45	0.00	0.16	0.13	0.04	3.07
2013	2.35	0.45	0.00	0.16	0.13	0.04	3.13
2014	2.41	0.46	0.00	0.16	0.13	0.04	3.19
2015	2.46	0.46	0.00	0.16	0.13	0.04	3.25
2016	2.51	0.47	0.00	0.16	0.13	0.04	3.30
2017	2.56	0.48	0.00	0.15	0.13	0.04	3.36

Adopted March 18, 1998

Table J-5

PG&E Service Area
High Price Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

	Utility Electric Generation			
		Transportation		Total
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**
1990				3.55
1991				3.08
1992				2.80
1993				3.02
1994				2.26
1995				2.21
1996				2.32
1997	1.78	0.23	0.61	2.63
1998	1.70	0.30	0.57	2.57
1999	1.61	0.31	0.55	2.46
2000	1.65	0.32	0.40	2.38
2001	1.70	0.34	0.39	2.42
2002	1.75	0.35	0.37	2.47
2003	1.79	0.37	0.37	2.52
2004	1.83	0.38	0.36	2.57
2005	1.87	0.40	0.36	2.63
2006	1.91	0.42	0.35	2.68
2007	1.95	0.44	0.34	2.74
2008	2.00	0.45	0.34	2.79
2009	2.04	0.47	0.33	2.84
2010	2.14	0.43	0.32	2.89
2011	2.20	0.43	0.32	2.95
2012	2.25	0.44	0.32	3.01
2013	2.31	0.44	0.32	3.07
2014	2.36	0.45	0.32	3.13
2015	2.41	0.45	0.32	3.18
2016	2.46	0.46	0.32	3.24
2017	2.51	0.47	0.32	3.29

Adopted March 18, 1998

Table J-5 (continued)

PG&E Service Area
High Price Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Utility Electric Generation				Cogen
		Transportation		Total	Gas
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990				3.09	3.09
1991				2.79	2.79
1992				2.61	2.61
1993				2.88	2.88
1994				2.20	2.20
1995				2.21	2.21
1996				2.37	2.37
1997	1.85	0.24	0.63	2.73	2.73
1998	1.81	0.32	0.60	2.74	2.74
1999	1.75	0.33	0.60	2.68	2.68
2000	1.85	0.36	0.45	2.66	2.66
2001	1.96	0.39	0.45	2.79	2.79
2002	2.07	0.41	0.44	2.93	2.93
2003	2.18	0.45	0.45	3.08	3.08
2004	2.30	0.48	0.46	3.24	3.24
2005	2.44	0.52	0.46	3.42	3.42
2006	2.57	0.56	0.47	3.61	3.61
2007	2.72	0.61	0.48	3.82	3.82
2008	2.88	0.65	0.48	4.02	4.02
2009	3.05	0.70	0.49	4.25	4.25
2010	3.31	0.67	0.50	4.48	4.48
2011	3.52	0.70	0.52	4.73	4.73
2012	3.74	0.73	0.53	5.00	5.00
2013	3.97	0.76	0.55	5.28	5.28
2014	4.21	0.80	0.57	5.57	5.57
2015	4.45	0.84	0.58	5.88	5.88
2016	4.71	0.89	0.61	6.20	6.20
2017	4.97	0.93	0.63	6.53	6.53

Adopted March 18, 1998

Table J-6

SoCal Gas Service Area
High Price Case
End-use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.40	6.76	5.99	4.28	3.79	3.37	3.67	3.67	4.75
1991	6.99	7.34	7.34	3.91	3.64	2.86	3.22	3.22	4.72
1992	6.82	7.66	6.40	5.00	3.75	2.82	3.13	3.13	4.78
1993	7.24	7.65	6.71	4.98	3.73	3.16	3.14	3.14	5.01
1994	7.03	6.81	6.59	3.32	2.48	2.48	2.65	2.65	4.60
1995	6.69	6.55	5.85	2.39	2.29	2.01	2.26	2.26	4.26
1996	6.72	5.78	4.97	2.73	2.68	2.43	2.94	2.94	4.49
1997	6.75	5.01	4.08	3.07	3.06	2.85	2.87	2.87	4.34
1998	6.61	4.88	3.95	2.95	2.94	2.74	2.72	2.72	4.16
1999	6.43	4.72	3.81	2.80	2.79	2.63	2.54	2.54	3.93
2000	6.33	4.64	3.74	2.69	2.69	2.71	2.41	2.41	3.79
2001	6.35	4.68	3.79	2.75	2.75	2.77	2.48	2.48	3.82
2002	6.35	4.70	3.83	2.81	2.81	2.84	2.54	2.54	3.84
2003	6.40	4.75	3.88	2.89	2.89	2.92	2.62	2.62	3.92
2004	6.31	4.72	3.88	2.95	2.95	2.99	2.69	2.69	3.90
2005	6.40	4.80	3.95	3.02	3.02	3.05	2.76	2.76	3.99
2006	6.33	4.78	3.97	3.08	3.07	3.11	2.82	2.82	3.99
2007	6.32	4.79	3.99	3.20	3.19	3.23	2.94	2.94	4.07
2008	6.32	4.82	4.04	3.26	3.25	3.28	3.01	3.01	4.10
2009	6.44	4.92	4.12	3.33	3.33	3.36	3.08	3.08	4.17
2010	6.45	4.95	4.16	3.34	3.34	3.37	3.09	3.09	4.18
2011	6.45	4.98	4.21	3.41	3.41	3.44	3.16	3.16	4.21
2012	6.52	5.05	4.28	3.48	3.48	3.51	3.23	3.23	4.28
2013	6.53	5.09	4.33	3.55	3.54	3.57	3.30	3.30	4.32
2014	6.60	5.16	4.40	3.61	3.61	3.64	3.37	3.37	4.38
2015	6.62	5.20	4.46	3.68	3.68	3.71	3.44	3.44	4.43
2016	6.66	5.25	4.51	3.75	3.74	3.77	3.50	3.50	4.48
2017	6.70	5.30	4.57	3.81	3.81	3.84	3.57	3.57	4.54

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7; 1996 is interpolated.
- Commodity: Nontransportation component of the California natural gas border price; fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border, fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- SoCal Gas Margin: Distribution and administration costs associated with running the SoCal Gas pipeline system.
- PITCO/POPCO: Global settlement associated with PITCO and POPCO long term supply contracts.
- Regulatory: Includes balancing accounts, social, environmental, and other regulatory accounts.

Adopted March 18, 1998

Table J-7

SoCal Gas Service Area
High Price Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.40
1991							6.99
1992							6.82
1993							7.24
1994							7.03
1995							6.69
1996							6.72
1997	2.15	0.36	0.03	3.83	0.12	0.26	6.75
1998	2.02	0.37	0.03	3.81	0.12	0.26	6.61
1999	1.90	0.37	0.03	3.75	0.12	0.26	6.43
2000	1.97	0.37	0.02	3.72	0.00	0.26	6.33
2001	2.03	0.37	0.02	3.68	0.00	0.26	6.35
2002	2.10	0.37	0.01	3.62	0.00	0.26	6.35
2003	2.15	0.37	0.01	3.61	0.00	0.26	6.40
2004	2.20	0.38	0.00	3.48	0.00	0.26	6.31
2005	2.25	0.38	0.00	3.50	0.00	0.26	6.40
2006	2.31	0.38	0.00	3.38	0.00	0.26	6.33
2007	2.36	0.36	0.00	3.34	0.00	0.26	6.32
2008	2.42	0.37	0.00	3.27	0.00	0.26	6.32
2009	2.47	0.38	0.00	3.33	0.00	0.26	6.44
2010	2.54	0.37	0.00	3.28	0.00	0.26	6.45
2011	2.61	0.37	0.00	3.21	0.00	0.26	6.45
2012	2.68	0.37	0.00	3.21	0.00	0.26	6.52
2013	2.74	0.38	0.00	3.16	0.00	0.26	6.53
2014	2.81	0.38	0.00	3.15	0.00	0.26	6.60
2015	2.88	0.38	0.00	3.10	0.00	0.26	6.62
2016	2.95	0.38	0.00	3.07	0.00	0.26	6.66
2017	3.01	0.38	0.00	3.04	0.00	0.26	6.70

Adopted March 18, 1998

Table J-7 (continued)

SoCal Gas Service Area
High Price Case
Commercial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.76
1991							7.34
1992							7.66
1993							7.65
1994							6.81
1995							6.55
1996							5.78
1997	2.15	0.36	0.03	2.14	0.12	0.21	5.01
1998	2.02	0.37	0.03	2.13	0.12	0.21	4.88
1999	1.90	0.37	0.03	2.10	0.12	0.21	4.72
2000	1.97	0.37	0.02	2.08	0.00	0.21	4.64
2001	2.03	0.37	0.02	2.06	0.00	0.21	4.68
2002	2.10	0.37	0.01	2.02	0.00	0.21	4.70
2003	2.15	0.37	0.01	2.02	0.00	0.21	4.75
2004	2.20	0.38	0.00	1.94	0.00	0.21	4.72
2005	2.25	0.38	0.00	1.96	0.00	0.21	4.80
2006	2.31	0.38	0.00	1.89	0.00	0.21	4.78
2007	2.36	0.36	0.00	1.86	0.00	0.21	4.79
2008	2.42	0.37	0.00	1.83	0.00	0.21	4.82
2009	2.47	0.38	0.00	1.86	0.00	0.21	4.92
2010	2.54	0.37	0.00	1.83	0.00	0.21	4.95
2011	2.61	0.37	0.00	1.80	0.00	0.21	4.98
2012	2.68	0.37	0.00	1.79	0.00	0.21	5.05
2013	2.74	0.38	0.00	1.76	0.00	0.21	5.09
2014	2.81	0.38	0.00	1.76	0.00	0.21	5.16
2015	2.88	0.38	0.00	1.73	0.00	0.21	5.20
2016	2.95	0.38	0.00	1.72	0.00	0.21	5.25
2017	3.01	0.38	0.00	1.70	0.00	0.21	5.30

Adopted March 18, 1998

Table J-7 (continued)

SoCal Gas Service Area
High Price Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							5.99
1991							7.34
1992							6.40
1993							6.71
1994							6.59
1995							5.85
1996							4.97
1997	2.15	0.36	0.03	1.16	0.12	0.25	4.08
1998	2.02	0.37	0.03	1.16	0.12	0.25	3.95
1999	1.90	0.37	0.03	1.14	0.12	0.25	3.81
2000	1.97	0.37	0.02	1.13	0.00	0.25	3.74
2001	2.03	0.37	0.02	1.12	0.00	0.25	3.79
2002	2.10	0.37	0.01	1.10	0.00	0.25	3.83
2003	2.15	0.37	0.01	1.10	0.00	0.25	3.88
2004	2.20	0.38	0.00	1.06	0.00	0.25	3.88
2005	2.25	0.38	0.00	1.06	0.00	0.25	3.95
2006	2.31	0.38	0.00	1.03	0.00	0.25	3.97
2007	2.36	0.36	0.00	1.01	0.00	0.25	3.99
2008	2.42	0.37	0.00	0.99	0.00	0.25	4.04
2009	2.47	0.38	0.00	1.01	0.00	0.25	4.12
2010	2.54	0.37	0.00	1.00	0.00	0.25	4.16
2011	2.61	0.37	0.00	0.98	0.00	0.25	4.21
2012	2.68	0.37	0.00	0.97	0.00	0.25	4.28
2013	2.74	0.38	0.00	0.96	0.00	0.25	4.33
2014	2.81	0.38	0.00	0.96	0.00	0.25	4.40
2015	2.88	0.38	0.00	0.94	0.00	0.25	4.46
2016	2.95	0.38	0.00	0.93	0.00	0.25	4.51
2017	3.01	0.38	0.00	0.92	0.00	0.25	4.57

Adopted March 18, 1998

Table J-8

SoCal Gas Service Area
High Price Case
Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.28
1991							3.91
1992							5.00
1993							4.98
1994							3.32
1995							2.39
1996							2.73
1997	2.19	0.16	0.13	0.42	0.12	0.06	3.07
1998	2.01	0.22	0.13	0.42	0.12	0.06	2.95
1999	1.89	0.23	0.08	0.42	0.12	0.06	2.80
2000	1.94	0.25	0.02	0.42	0.00	0.06	2.69
2001	2.00	0.26	0.02	0.42	0.00	0.06	2.75
2002	2.06	0.27	0.01	0.42	0.00	0.06	2.81
2003	2.10	0.31	0.01	0.41	0.00	0.06	2.89
2004	2.15	0.35	0.00	0.40	0.00	0.06	2.95
2005	2.20	0.36	0.00	0.40	0.00	0.06	3.02
2006	2.25	0.38	0.00	0.39	0.00	0.06	3.08
2007	2.30	0.45	0.00	0.39	0.00	0.06	3.20
2008	2.36	0.47	0.00	0.38	0.00	0.06	3.26
2009	2.41	0.48	0.00	0.39	0.00	0.06	3.33
2010	2.47	0.43	0.00	0.38	0.00	0.06	3.34
2011	2.54	0.44	0.00	0.38	0.00	0.06	3.41
2012	2.60	0.44	0.00	0.38	0.00	0.06	3.48
2013	2.67	0.45	0.00	0.37	0.00	0.06	3.55
2014	2.73	0.45	0.00	0.37	0.00	0.06	3.61
2015	2.79	0.46	0.00	0.37	0.00	0.06	3.68
2016	2.86	0.47	0.00	0.37	0.00	0.06	3.75
2017	2.92	0.47	0.00	0.37	0.00	0.06	3.81

Adopted March 18, 1998

Table J-8 (continued)

SoCal Gas Service Area
High Price Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.79
1991							3.64
1992							3.75
1993							3.73
1994							2.48
1995							2.29
1996							2.68
1997	2.19	0.16	0.13	0.41	0.12	0.06	3.06
1998	2.01	0.22	0.13	0.42	0.12	0.06	2.94
1999	1.89	0.23	0.08	0.42	0.12	0.06	2.79
2000	1.94	0.25	0.02	0.42	0.00	0.06	2.69
2001	2.00	0.26	0.02	0.42	0.00	0.06	2.75
2002	2.06	0.27	0.01	0.41	0.00	0.06	2.81
2003	2.10	0.31	0.01	0.41	0.00	0.06	2.89
2004	2.15	0.35	0.00	0.40	0.00	0.06	2.95
2005	2.20	0.36	0.00	0.40	0.00	0.06	3.02
2006	2.25	0.38	0.00	0.39	0.00	0.06	3.07
2007	2.30	0.45	0.00	0.38	0.00	0.06	3.19
2008	2.36	0.47	0.00	0.38	0.00	0.06	3.25
2009	2.41	0.48	0.00	0.38	0.00	0.06	3.33
2010	2.47	0.43	0.00	0.38	0.00	0.06	3.34
2011	2.54	0.44	0.00	0.37	0.00	0.06	3.41
2012	2.60	0.44	0.00	0.37	0.00	0.06	3.48
2013	2.67	0.45	0.00	0.37	0.00	0.06	3.54
2014	2.73	0.45	0.00	0.37	0.00	0.06	3.61
2015	2.79	0.46	0.00	0.37	0.00	0.06	3.68
2016	2.86	0.47	0.00	0.36	0.00	0.06	3.74
2017	2.92	0.47	0.00	0.36	0.00	0.06	3.81

Adopted March 18, 1998

Table J-8 (continued)

SoCal Gas Service Area
High Price Case
TEOR Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.37
1991							2.86
1992							2.82
1993							3.16
1994							2.48
1995							2.01
1996							2.43
1997	2.19	0.16	0.00	0.51	0.00	0.00	2.85
1998	2.01	0.22	0.00	0.51	0.00	0.00	2.74
1999	1.89	0.23	0.00	0.51	0.00	0.00	2.63
2000	1.94	0.25	0.00	0.51	0.00	0.00	2.71
2001	2.00	0.26	0.00	0.51	0.00	0.00	2.77
2002	2.06	0.27	0.00	0.51	0.00	0.00	2.84
2003	2.10	0.31	0.00	0.50	0.00	0.00	2.92
2004	2.15	0.35	0.00	0.49	0.00	0.00	2.99
2005	2.20	0.36	0.00	0.49	0.00	0.00	3.05
2006	2.25	0.38	0.00	0.48	0.00	0.00	3.11
2007	2.30	0.45	0.00	0.47	0.00	0.00	3.23
2008	2.36	0.47	0.00	0.46	0.00	0.00	3.28
2009	2.41	0.48	0.00	0.47	0.00	0.00	3.36
2010	2.47	0.43	0.00	0.47	0.00	0.00	3.37
2011	2.54	0.44	0.00	0.46	0.00	0.00	3.44
2012	2.60	0.44	0.00	0.46	0.00	0.00	3.51
2013	2.67	0.45	0.00	0.46	0.00	0.00	3.57
2014	2.73	0.45	0.00	0.45	0.00	0.00	3.64
2015	2.79	0.46	0.00	0.45	0.00	0.00	3.71
2016	2.86	0.47	0.00	0.45	0.00	0.00	3.77
2017	2.92	0.47	0.00	0.45	0.00	0.00	3.84

Adopted March 18, 1998

Table J-9

SoCal Gas Service Area
High Price Case
Cogen Noncore Generation Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.67
1991							3.22
1992							3.13
1993							3.14
1994							2.65
1995							2.26
1996							2.94
1997	1.99	0.39	0.13	0.17	0.12	0.07	2.87
1998	2.00	0.24	0.13	0.17	0.12	0.06	2.72
1999	1.89	0.23	0.08	0.18	0.12	0.05	2.54
2000	1.94	0.25	0.02	0.18	0.00	0.03	2.41
2001	2.00	0.26	0.02	0.17	0.00	0.03	2.48
2002	2.06	0.27	0.01	0.17	0.00	0.03	2.54
2003	2.10	0.31	0.01	0.17	0.00	0.03	2.62
2004	2.15	0.35	0.00	0.17	0.00	0.03	2.69
2005	2.20	0.36	0.00	0.17	0.00	0.03	2.76
2006	2.25	0.38	0.00	0.16	0.00	0.03	2.82
2007	2.30	0.45	0.00	0.16	0.00	0.03	2.94
2008	2.36	0.47	0.00	0.16	0.00	0.03	3.01
2009	2.41	0.48	0.00	0.16	0.00	0.03	3.08
2010	2.47	0.43	0.00	0.16	0.00	0.03	3.09
2011	2.54	0.44	0.00	0.16	0.00	0.03	3.16
2012	2.60	0.44	0.00	0.16	0.00	0.03	3.23
2013	2.67	0.45	0.00	0.16	0.00	0.03	3.30
2014	2.73	0.45	0.00	0.15	0.00	0.03	3.37
2015	2.79	0.46	0.00	0.15	0.00	0.03	3.44
2016	2.86	0.47	0.00	0.15	0.00	0.03	3.50
2017	2.92	0.47	0.00	0.15	0.00	0.03	3.57

Adopted March 18, 1998

Table J-9 (continued)

SoCal Gas Service Area
High Price Case
Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SoCal Gas Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.67
1991							3.22
1992							3.13
1993							3.14
1994							2.65
1995							2.26
1996							2.94
1997	1.99	0.39	0.13	0.17	0.12	0.07	2.87
1998	2.00	0.24	0.13	0.17	0.12	0.06	2.72
1999	1.89	0.23	0.08	0.18	0.12	0.05	2.54
2000	1.94	0.25	0.02	0.18	0.00	0.03	2.41
2001	2.00	0.26	0.02	0.17	0.00	0.03	2.48
2002	2.06	0.27	0.01	0.17	0.00	0.03	2.54
2003	2.10	0.31	0.01	0.17	0.00	0.03	2.62
2004	2.15	0.35	0.00	0.17	0.00	0.03	2.69
2005	2.20	0.36	0.00	0.17	0.00	0.03	2.76
2006	2.25	0.38	0.00	0.16	0.00	0.03	2.82
2007	2.30	0.45	0.00	0.16	0.00	0.03	2.94
2008	2.36	0.47	0.00	0.16	0.00	0.03	3.01
2009	2.41	0.48	0.00	0.16	0.00	0.03	3.08
2010	2.47	0.43	0.00	0.16	0.00	0.03	3.09
2011	2.54	0.44	0.00	0.16	0.00	0.03	3.16
2012	2.60	0.44	0.00	0.16	0.00	0.03	3.23
2013	2.67	0.45	0.00	0.16	0.00	0.03	3.30
2014	2.73	0.45	0.00	0.15	0.00	0.03	3.37
2015	2.79	0.46	0.00	0.15	0.00	0.03	3.44
2016	2.86	0.47	0.00	0.15	0.00	0.03	3.50
2017	2.92	0.47	0.00	0.15	0.00	0.03	3.57

Adopted March 18, 1998

Table J-10

SoCal Gas Service Area
High Price Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

Year	Commodity	Transportation		Total Price
		Interstate	Intrastate	
1990				3.51
1991				3.11
1992				3.00
1993				3.02
1994				2.55
1995				2.20
1996				2.85
1997	1.94	0.38	0.48	2.80
1998	1.96	0.23	0.47	2.66
1999	1.84	0.22	0.41	2.48
2000	1.90	0.24	0.22	2.36
2001	1.95	0.25	0.21	2.42
2002	2.01	0.27	0.21	2.48
2003	2.05	0.30	0.20	2.56
2004	2.09	0.34	0.19	2.62
2005	2.15	0.35	0.19	2.69
2006	2.20	0.37	0.19	2.75
2007	2.25	0.44	0.18	2.87
2008	2.30	0.45	0.18	2.93
2009	2.35	0.47	0.18	3.00
2010	2.41	0.42	0.18	3.02
2011	2.48	0.43	0.18	3.08
2012	2.54	0.43	0.18	3.15
2013	2.60	0.44	0.18	3.22
2014	2.66	0.44	0.18	3.28
2015	2.73	0.45	0.18	3.35
2016	2.79	0.45	0.18	3.42
2017	2.85	0.46	0.17	3.49

Adopted March 18, 1998

Table J-10 (continued)

SoCal Gas Service Area
High Price Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Electricity Generation				**Cogen**
		Transportation		**Total**	**Gas**
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990				3.05	3.05
1991				2.81	2.81
1992				2.79	2.79
1993				2.88	2.88
1994				2.49	2.49
1995				2.20	2.20
1996				2.91	2.91
1997	2.01	0.40	0.50	2.91	2.91
1998	2.08	0.25	0.50	2.82	2.82
1999	2.01	0.25	0.45	2.70	2.70
2000	2.12	0.27	0.24	2.64	2.64
2001	2.25	0.29	0.25	2.79	2.79
2002	2.38	0.32	0.25	2.94	2.94
2003	2.50	0.37	0.25	3.12	3.12
2004	2.64	0.43	0.24	3.30	3.30
2005	2.79	0.46	0.25	3.50	3.50
2006	2.96	0.50	0.25	3.70	3.70
2007	3.13	0.62	0.25	4.00	4.00
2008	3.32	0.66	0.26	4.24	4.24
2009	3.51	0.70	0.27	4.49	4.49
2010	3.74	0.65	0.28	4.67	4.67
2011	3.97	0.69	0.29	4.95	4.95
2012	4.22	0.72	0.30	5.23	5.23
2013	4.47	0.75	0.31	5.53	5.53
2014	4.75	0.79	0.32	5.85	5.85
2015	5.03	0.83	0.33	6.19	6.19
2016	5.34	0.87	0.34	6.54	6.54
2017	5.65	0.91	0.35	6.91	6.91

Adopted March 18, 1998

Table J-11

SDG&E Service Area
High Price Case
End-Use Natural Gas Price Forecast Summary

1995 $ per mcf

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.43	6.61	6.40	4.41	4.41	0.00	3.71	3.71	5.06
1991	6.05	6.13	6.13	3.88	3.88	0.00	3.25	3.25	4.61
1992	6.45	6.67	6.67	4.02	4.02	0.00	3.20	3.20	4.71
1993	6.85	6.87	6.44	3.81	3.96	0.00	3.33	3.33	4.97
1994	6.89	6.71	5.53	3.60	3.90	0.00	3.04	3.04	4.88
1995	6.44	6.32	5.31	2.71	2.74	0.00	2.18	2.18	4.01
1996	6.66	6.25	5.02	3.01	3.03	0.00	2.53	2.53	4.41
1997	6.88	6.19	4.72	3.32	3.32	0.00	3.07	3.07	4.56
1998	6.69	6.00	4.56	3.15	3.15	0.00	2.99	2.99	4.37
1999	6.59	5.89	4.44	2.97	2.97	0.00	2.76	2.76	4.29
2000	6.63	5.94	4.49	2.97	2.97	0.00	2.76	2.76	4.30
2001	6.73	6.04	4.57	3.04	3.04	0.00	2.82	2.82	4.42
2002	6.55	5.89	4.51	3.09	3.09	0.00	2.88	2.88	4.09
2003	6.67	6.00	4.60	3.16	3.16	0.00	2.94	2.93	4.27
2004	6.66	6.00	4.63	3.22	3.22	0.00	3.00	3.00	4.27
2005	6.74	6.08	4.70	3.28	3.28	0.00	3.06	3.05	4.42
2006	6.71	6.06	4.72	3.33	3.33	0.00	3.12	3.11	4.41
2007	6.76	6.12	4.80	3.44	3.44	0.00	3.22	3.22	4.47
2008	6.76	6.12	4.83	3.49	3.49	0.00	3.28	3.27	4.51
2009	6.82	6.19	4.89	3.55	3.55	0.00	3.34	3.33	4.67
2010	6.83	6.20	4.91	3.57	3.57	0.00	3.36	3.35	4.75
2011	6.85	6.22	4.95	3.63	3.63	0.00	3.42	3.42	4.80
2012	6.90	6.28	5.01	3.69	3.69	0.00	3.48	3.48	4.92
2013	6.93	6.32	5.06	3.75	3.75	0.00	3.55	3.54	5.00
2014	6.99	6.37	5.12	3.81	3.81	0.00	3.61	3.61	5.12
2015	7.04	6.43	5.18	3.87	3.87	0.00	3.67	3.67	5.26
2016	7.08	6.47	5.23	3.93	3.93	0.00	3.74	3.73	5.34
2017	7.10	6.50	5.28	3.99	3.99	0.00	3.80	3.79	5.42

Adopted March 18, 1998

The following notes provide basic assumption in preparing the natural gas price forecast.

Notes:

- 1990-1995 total prices are historical , obtained from QFER 7; 1996 is interpolated.
- Commodity: Nontransportation component of the California natural gas border price, fuel costs are included.
- Transport: Weighted average interstate transport cost to deliver natural gas to the California border, fuel is not included.
- ITCS: An instate charge to recover interstate transition charges resultant from implementation of FERC Order 636.
- SDG&E Margin: Distribution and administration costs associated with running the SDG&E pipeline system and transmission charges to SoCal Gas.
- PITCO/POPCO: Global settlement associated with PITCO and POPCO long term supply contracts.
- Regulatory: Includes balancing accounts, social, environmental, and other regulatory accounts.

Table J-12

SDG&E Service
High Price Case
Residential Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.43
1991							6.05
1992							6.45
1993							6.85
1994							6.89
1995							6.44
1996							6.66
1997	2.09	0.25	0.03	4.24	0.00	0.27	6.88
1998	1.90	0.30	0.03	4.18	0.00	0.27	6.69
1999	1.77	0.30	0.03	4.20	0.00	0.27	6.59
2000	1.83	0.31	0.02	4.20	0.00	0.27	6.63
2001	1.89	0.32	0.02	4.23	0.00	0.27	6.73
2002	1.95	0.33	0.01	3.99	0.00	0.27	6.55
2003	2.00	0.35	0.01	4.03	0.00	0.27	6.67
2004	2.05	0.38	0.00	3.96	0.00	0.27	6.66
2005	2.10	0.39	0.00	3.98	0.00	0.27	6.74
2006	2.15	0.41	0.00	3.89	0.00	0.27	6.71
2007	2.20	0.47	0.00	3.82	0.00	0.27	6.76
2008	2.25	0.48	0.00	3.75	0.00	0.27	6.76
2009	2.30	0.50	0.00	3.75	0.00	0.27	6.82
2010	2.37	0.45	0.00	3.74	0.00	0.27	6.83
2011	2.43	0.46	0.00	3.69	0.00	0.27	6.85
2012	2.49	0.46	0.00	3.67	0.00	0.27	6.90
2013	2.56	0.47	0.00	3.64	0.00	0.27	6.93
2014	2.62	0.47	0.00	3.62	0.00	0.27	6.99
2015	2.68	0.48	0.00	3.61	0.00	0.27	7.04
2016	2.74	0.48	0.00	3.58	0.00	0.27	7.08
2017	2.81	0.49	0.00	3.54	0.00	0.27	7.10

Adopted March 18, 1998

Table J-12 (continued)

SDG&E Service Area
High Price Case
Commercial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.61
1991							6.13
1992							6.67
1993							6.87
1994							6.71
1995							6.32
1996							6.25
1997	2.09	0.25	0.03	3.70	0.00	0.12	6.19
1998	1.90	0.30	0.03	3.65	0.00	0.12	6.00
1999	1.77	0.30	0.03	3.66	0.00	0.12	5.89
2000	1.83	0.31	0.02	3.66	0.00	0.12	5.94
2001	1.89	0.32	0.02	3.69	0.00	0.12	6.04
2002	1.95	0.33	0.01	3.48	0.00	0.12	5.89
2003	2.00	0.35	0.01	3.52	0.00	0.12	6.00
2004	2.05	0.38	0.00	3.45	0.00	0.12	6.00
2005	2.10	0.39	0.00	3.47	0.00	0.12	6.08
2006	2.15	0.41	0.00	3.39	0.00	0.12	6.06
2007	2.20	0.47	0.00	3.33	0.00	0.12	6.12
2008	2.25	0.48	0.00	3.27	0.00	0.12	6.12
2009	2.30	0.50	0.00	3.27	0.00	0.12	6.19
2010	2.37	0.45	0.00	3.26	0.00	0.12	6.20
2011	2.43	0.46	0.00	3.21	0.00	0.12	6.22
2012	2.49	0.46	0.00	3.20	0.00	0.12	6.28
2013	2.56	0.47	0.00	3.17	0.00	0.12	6.32
2014	2.62	0.47	0.00	3.16	0.00	0.12	6.37
2015	2.68	0.48	0.00	3.15	0.00	0.12	6.43
2016	2.74	0.48	0.00	3.12	0.00	0.12	6.47
2017	2.81	0.49	0.00	3.08	0.00	0.12	6.50

Adopted March 18, 1998

Table J-12 (continued)

SDG&E Service Area
High Price Case
Industrial Core Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							6.40
1991							6.13
1992							6.67
1993							6.44
1994							5.53
1995							5.31
1996							5.02
1997	2.09	0.25	0.03	2.23	0.00	0.12	4.72
1998	1.90	0.30	0.03	2.20	0.00	0.12	4.56
1999	1.77	0.30	0.03	2.21	0.00	0.12	4.44
2000	1.83	0.31	0.02	2.21	0.00	0.12	4.49
2001	1.89	0.32	0.02	2.23	0.00	0.12	4.57
2002	1.95	0.33	0.01	2.10	0.00	0.12	4.51
2003	2.00	0.35	0.01	2.12	0.00	0.12	4.60
2004	2.05	0.38	0.00	2.09	0.00	0.12	4.63
2005	2.10	0.39	0.00	2.09	0.00	0.12	4.70
2006	2.15	0.41	0.00	2.05	0.00	0.12	4.72
2007	2.20	0.47	0.00	2.01	0.00	0.12	4.80
2008	2.25	0.48	0.00	1.97	0.00	0.12	4.83
2009	2.30	0.50	0.00	1.98	0.00	0.12	4.89
2010	2.37	0.45	0.00	1.97	0.00	0.12	4.91
2011	2.43	0.46	0.00	1.94	0.00	0.12	4.95
2012	2.49	0.46	0.00	1.93	0.00	0.12	5.01
2013	2.56	0.47	0.00	1.91	0.00	0.12	5.06
2014	2.62	0.47	0.00	1.91	0.00	0.12	5.12
2015	2.68	0.48	0.00	1.90	0.00	0.12	5.18
2016	2.74	0.48	0.00	1.88	0.00	0.12	5.23
2017	2.81	0.49	0.00	1.86	0.00	0.12	5.28

Adopted March 18, 1998

Table J-13

SDG&E Service Area

High Price Case

Commercial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.41
1991							3.88
1992							4.02
1993							3.81
1994							3.60
1995							2.71
1996							3.01
1997	2.09	0.25	0.14	0.81	0.00	0.03	3.32
1998	1.90	0.30	0.13	0.78	0.00	0.03	3.15
1999	1.77	0.30	0.09	0.77	0.00	0.03	2.97
2000	1.83	0.31	0.02	0.77	0.00	0.03	2.97
2001	1.89	0.32	0.02	0.78	0.00	0.03	3.04
2002	1.95	0.33	0.01	0.77	0.00	0.03	3.09
2003	2.00	0.35	0.01	0.77	0.00	0.03	3.16
2004	2.05	0.38	0.00	0.76	0.00	0.03	3.22
2005	2.10	0.39	0.00	0.76	0.00	0.03	3.28
2006	2.15	0.41	0.00	0.75	0.00	0.03	3.33
2007	2.20	0.47	0.00	0.74	0.00	0.03	3.44
2008	2.25	0.48	0.00	0.73	0.00	0.03	3.49
2009	2.30	0.50	0.00	0.72	0.00	0.03	3.55
2010	2.37	0.45	0.00	0.71	0.00	0.03	3.57
2011	2.43	0.46	0.00	0.71	0.00	0.03	3.63
2012	2.49	0.46	0.00	0.70	0.00	0.03	3.69
2013	2.56	0.47	0.00	0.69	0.00	0.03	3.75
2014	2.62	0.47	0.00	0.69	0.00	0.03	3.81
2015	2.68	0.48	0.00	0.68	0.00	0.03	3.87
2016	2.74	0.48	0.00	0.67	0.00	0.03	3.93
2017	2.81	0.49	0.00	0.66	0.00	0.03	3.99

Adopted March 18, 1998

Table J-13 (continued)

SDG&E Service Area
High Price Case
Industrial Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							4.41
1991							3.88
1992							4.02
1993							3.96
1994							3.90
1995							2.74
1996							3.03
1997	2.09	0.25	0.14	0.81	0.00	0.03	3.32
1998	1.90	0.30	0.13	0.78	0.00	0.03	3.15
1999	1.77	0.30	0.09	0.77	0.00	0.03	2.97
2000	1.83	0.31	0.02	0.77	0.00	0.03	2.97
2001	1.89	0.32	0.02	0.78	0.00	0.03	3.04
2002	1.95	0.33	0.01	0.77	0.00	0.03	3.09
2003	2.00	0.35	0.01	0.77	0.00	0.03	3.16
2004	2.05	0.38	0.00	0.76	0.00	0.03	3.22
2005	2.10	0.39	0.00	0.76	0.00	0.03	3.28
2006	2.15	0.41	0.00	0.75	0.00	0.03	3.33
2007	2.20	0.47	0.00	0.74	0.00	0.03	3.44
2008	2.25	0.48	0.00	0.73	0.00	0.03	3.49
2009	2.30	0.50	0.00	0.72	0.00	0.03	3.55
2010	2.37	0.45	0.00	0.71	0.00	0.03	3.57
2011	2.43	0.46	0.00	0.71	0.00	0.03	3.63
2012	2.49	0.46	0.00	0.70	0.00	0.03	3.69
2013	2.56	0.47	0.00	0.69	0.00	0.03	3.75
2014	2.62	0.47	0.00	0.69	0.00	0.03	3.81
2015	2.68	0.48	0.00	0.68	0.00	0.03	3.87
2016	2.74	0.48	0.00	0.67	0.00	0.03	3.93
2017	2.81	0.49	0.00	0.66	0.00	0.03	3.99

Adopted March 18, 1998

Table J-14

SDG&E Service Area
High Price Case
Cogen Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	2.09	0.25	0.14	0.49	0.00	0.10	3.07
1998	1.90	0.30	0.13	0.56	0.00	0.10	2.99
1999	1.77	0.30	0.09	0.50	0.00	0.10	2.76
2000	1.83	0.31	0.02	0.49	0.00	0.10	2.76
2001	1.89	0.32	0.02	0.49	0.00	0.10	2.82
2002	1.95	0.33	0.01	0.49	0.00	0.10	2.88
2003	2.00	0.35	0.01	0.47	0.00	0.10	2.94
2004	2.05	0.38	0.00	0.47	0.00	0.10	3.00
2005	2.10	0.39	0.00	0.47	0.00	0.10	3.06
2006	2.15	0.41	0.00	0.46	0.00	0.10	3.12
2007	2.20	0.47	0.00	0.45	0.00	0.10	3.22
2008	2.25	0.48	0.00	0.44	0.00	0.10	3.28
2009	2.30	0.50	0.00	0.44	0.00	0.10	3.34
2010	2.37	0.45	0.00	0.43	0.00	0.10	3.36
2011	2.43	0.46	0.00	0.43	0.00	0.10	3.42
2012	2.49	0.46	0.00	0.42	0.00	0.10	3.48
2013	2.56	0.47	0.00	0.42	0.00	0.10	3.55
2014	2.62	0.47	0.00	0.42	0.00	0.10	3.61
2015	2.68	0.48	0.00	0.41	0.00	0.10	3.67
2016	2.74	0.48	0.00	0.41	0.00	0.10	3.74
2017	2.81	0.49	0.00	0.40	0.00	0.10	3.80

Adopted March 18, 1998

Table J-14 (continued)

SDG&E Service Area
High Price Case
Electricity Generation Noncore Natural Gas Price Forecast

1995 $ per mcf

	Interstate Charges		SDG&E Instate Charges				
Year	**Commodity**	**Transport**	**ITCS**	**Margin**	**Pitco/Popco**	**Regulatory**	**Total**
1990							3.71
1991							3.25
1992							3.20
1993							3.33
1994							3.04
1995							2.18
1996							2.53
1997	2.09	0.25	0.14	0.49	0.00	0.10	3.07
1998	1.90	0.30	0.13	0.56	0.00	0.10	2.99
1999	1.77	0.30	0.09	0.50	0.00	0.10	2.76
2000	1.83	0.31	0.02	0.49	0.00	0.10	2.76
2001	1.89	0.32	0.02	0.49	0.00	0.10	2.82
2002	1.95	0.33	0.01	0.49	0.00	0.10	2.88
2003	2.00	0.35	0.01	0.47	0.00	0.10	2.93
2004	2.05	0.38	0.00	0.47	0.00	0.10	3.00
2005	2.10	0.39	0.00	0.47	0.00	0.10	3.05
2006	2.15	0.41	0.00	0.46	0.00	0.10	3.11
2007	2.20	0.47	0.00	0.45	0.00	0.10	3.22
2008	2.25	0.48	0.00	0.44	0.00	0.10	3.27
2009	2.30	0.50	0.00	0.44	0.00	0.10	3.33
2010	2.37	0.45	0.00	0.43	0.00	0.10	3.35
2011	2.43	0.46	0.00	0.43	0.00	0.10	3.42
2012	2.49	0.46	0.00	0.42	0.00	0.10	3.48
2013	2.56	0.47	0.00	0.42	0.00	0.10	3.54
2014	2.62	0.47	0.00	0.42	0.00	0.10	3.61
2015	2.68	0.48	0.00	0.41	0.00	0.10	3.67
2016	2.74	0.48	0.00	0.41	0.00	0.10	3.73
2017	2.81	0.49	0.00	0.40	0.00	0.10	3.79

Adopted March 18, 1998

Table J-15

SDG&E Service Area
High Price Case
Electricity Generation Gas Price Forecast

1995 $ per mmBtu

		Transportation		Total
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**
1990			2.11	3.60
1991			2.03	3.16
1992			2.10	3.10
1993			2.12	3.24
1994			2.09	2.98
1995			2.09	2.14
1996			1.39	2.50
1997	2.03	0.24	0.72	3.00
1998	1.86	0.29	0.77	2.92
1999	1.73	0.30	0.67	2.69
2000	1.79	0.30	0.60	2.69
2001	1.84	0.31	0.60	2.75
2002	1.90	0.32	0.59	2.81
2003	1.95	0.35	0.57	2.86
2004	2.00	0.37	0.56	2.93
2005	2.04	0.38	0.55	2.98
2006	2.09	0.40	0.55	3.04
2007	2.14	0.46	0.54	3.14
2008	2.19	0.47	0.53	3.19
2009	2.24	0.48	0.52	3.25
2010	2.31	0.44	0.52	3.27
2011	2.37	0.45	0.52	3.34
2012	2.43	0.45	0.51	3.40
2013	2.49	0.46	0.51	3.46
2014	2.55	0.46	0.50	3.52
2015	2.62	0.47	0.50	3.58
2016	2.68	0.47	0.49	3.64
2017	2.74	0.48	0.49	3.70

Adopted March 18, 1998

Table J-15 (continued)

SDG&E Service Area
High Price Case
Electricity Generation Gas Price Forecast

Nominal $ per mmBtu

	Electricity Generation				Cogen Gas
		Transportation		Total	
Year	**Commodity**	**Interstate**	**Intrastate**	**Price**	**Price**
1990			1.84	3.13	3.13
1991			1.83	2.86	2.86
1992			1.95	2.88	2.88
1993			2.02	3.09	3.09
1994			2.04	2.90	2.90
1995			2.09	2.14	2.14
1996			1.42	2.55	2.55
1997	2.11	0.25	0.75	3.12	3.12
1998	1.98	0.31	0.82	3.10	3.10
1999	1.88	0.32	0.73	2.93	2.93
2000	2.00	0.34	0.67	3.01	3.01
2001	2.12	0.36	0.69	3.17	3.17
2002	2.25	0.38	0.70	3.33	3.33
2003	2.38	0.42	0.69	3.49	3.49
2004	2.51	0.47	0.70	3.68	3.68
2005	2.66	0.50	0.72	3.88	3.88
2006	2.82	0.53	0.74	4.09	4.09
2007	2.99	0.64	0.75	4.38	4.38
2008	3.17	0.68	0.76	4.61	4.61
2009	3.35	0.72	0.78	4.86	4.86
2010	3.57	0.69	0.81	5.07	5.07
2011	3.80	0.72	0.83	5.35	5.35
2012	4.04	0.75	0.85	5.64	5.64
2013	4.29	0.79	0.87	5.95	5.95
2014	4.55	0.82	0.90	6.27	6.27
2015	4.83	0.86	0.92	6.61	6.61
2016	5.12	0.90	0.94	6.97	6.97
2017	5.43	0.95	0.97	7.34	7.34

Adopted March 18, 1998

APPENDIX K

GDP IMPLICIT PRICE DEFLATOR SERIES

(1993=100)

Year	Index	Percent Change
1970	28.41	N/A
1971	29.89	5.2
1972	31.17	4.3
1973	32.94	5.7
1974	35.79	8.7
1975	39.22	9.6
1976	41.43	5.6
1977	44.03	6.3
1978	47.40	7.7
1979	51.41	8.5
1980	56.12	9.2
1981	61.30	9.2
1982	65.18	6.3
1983	67.92	4.2
1984	70.60	3.9
1985	72.92	3.3
1986	74.88	2.7
1987	77.22	3.1
1988	80.06	3.7
1989	83.42	4.2
1990	86.98	4.3
1991	90.48	4.0
1992	92.96	2.7
1993	95.38	2.6
1994	97.56	2.3
1995	100.00	2.5
1996	101.96	2.0
1997	103.91	1.9
1998	106.31	2.3
1999	108.95	2.5
2000	111.90	2.7
2001	115.08	2.9
2002	118.43	2.9
2003	121.99	3.0
2004	125.88	3.2
2005	130.15	3.4
2006	134.67	3.5
2007	139.42	3.5
2008	144.39	3.6
2009	149.53	3.6
2010	154.83	3.5
2011	160.40	3.6
2012	166.11	3.6
2013	171.98	3.5
2014	178.13	3.6
2015	184.58	3.6
2016	191.31	3.7
2017	198.30	3.7

Source: 1970-2017 DRI TREND25YR0297 FORECAST